



Pipestone Energy Corp
Annual Information Form
Year ended December 31, 2022

March 8, 2023

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Selected Terms

In this AIF, the terms set forth below have the following meanings, unless the context requires or indicates otherwise:

2019 Regulations means the regulations accompanying the Modernized IOGA.

AB LLR Program means the Alberta Licensee Liability Rating Program.

AB LMF means the new Alberta Liability Management Framework.

AB LMR Program means the Alberta Liability Management Program.

AB OWL Program means the Alberta Oilfield Waste Liability Program.

abandonment and reclamation costs means all costs associated with the process of restoring the Company's property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.

ABC means the voluntary area-based closure program implemented by the AER.

ABCA means the *Business Corporations Act* (Alberta), R.S.A. 2000, c B-9, as amended, including the regulations promulgated thereunder.

Additional Facility means the \$70 million additional facility forming part of the RBL.

AECO means the physical storage and trading hub for natural gas on TC Energy's Alberta Transmission System, which is the delivery point for the various benchmark Alberta index prices.

AER means the Alberta Energy Regulator.

AIF means this annual information form.

Alliance means Alliance Pipeline Limited Partnership and Alliance Pipeline L.P. and/or their respective affiliates, as is appropriate in the context.

Alliance Pipeline means the 3,848-kilometre integrated Canadian and U.S. natural gas transmission pipeline system which delivers natural gas from the Western Canadian Sedimentary Basin and the Williston Basin to the Chicago market hub that is owned and operated by Alliance.

Al Mehwar means Al Mehwar Commercial Investments LLC, an affiliate of Amwal Investments LLC.

Al Mehwar Nomination Agreement means the nomination agreement between Pipestone Energy and Al Mehwar dated September 24, 2021.

Applicable Securities Laws means all applicable securities laws, the respective regulations, rules and orders made thereunder, and all applicable policies and notices issued by the securities regulatory authorities in Canada.

Audit Committee means the Audit Committee of the Board.

BC Commission means the BC Oil and Gas Commission.

BC EAO means the British Columbia's Environmental Assessment Office.

BC EMA means the *Environmental Management Act* (British Columbia).

Basin means a large natural depression on the earth's surface in which sediments generally brought by water or wind accumulate and in the case of oil and natural gas exploration and development it means such a depression that has been buried by subsequent geological activity.

Bill C-12 *Bill C-12: an Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050.*

Blackbird means Blackbird Energy Inc.

Blueberry Decision means the British Columbia Supreme Court's judgement in *Yahey v British Columbia*.

BRFN means the Blueberry River First Nation.

Board of Directors or **Board** means the board of directors of the Company.

Brexit means the United Kingdom's departure from the European Union on January 31, 2020.

CEAA 2012 means the *Canadian Environmental Assessment Act, 2012*.

CEO means chief executive officer.

CER means the Canada Energy Regulator.

CERA means the *Canada Energy Regulator Act*.

CETA means the Comprehensive Economic and Trade Agreement.

CFS means the Clean Fuel Standard.

CGL Pipeline means the Coastal GasLink pipeline.

CLA means the *Climate Leadership Act*.

CLP means the Climate Leadership Plan

CNOR LP means Canadian Non-Operated Resources LP.

CNOR Nomination Agreement means the nomination agreement between Pipestone Energy and CNOR LP entered upon the close of the Corporate Acquisition.

CNOR Registration Rights Agreement means the registration rights agreement between Pipestone Energy and CNOR LP entered upon the close of the Corporate Acquisition.

CNRL means Canadian Natural Resources Limited and its affiliates.

CNRL Gold Creek Plant means CNRL's Gold Creek Sour Gas processing facility.

CO₂e means carbon dioxide equivalents.

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

Common Shares means the common shares of the Company.

condensate means a mixture of hydrocarbons consisting primarily of pentanes and heavier liquids extracted from natural gas.

Condensate Fairway means the segment of the Montney geologic trend, which includes the Pipestone Area, whereby the typical average initial condensate- to-gas ratios are greater than 75 bbl/MMcf.

Consensus Document means a set of initiatives co-developed by the Government of British Columbia and the Treaty 8 Nations.

Conventional Natural Gas means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

Conversion Price means the Convertible Preferred Share conversion price of \$0.85 per Common Share.

Convertible Preferred Share Financing means the financing pursuant to which Pipestone Energy entered into subscription agreements with the Investors for Convertible Preferred Shares with proceeds to Pipestone Energy of approximately \$67 million, net of transaction costs.

Convertible Preferred Shares means the 70,000 convertible preferred shares in the capital of the Company issued on September 15, 2020. See "*Description of Capital Structure – Convertible Preferred Shares*" section below for more details.

Corporate Acquisition means Pipestone Oil Corp's reverse takeover of, and amalgamation with Blackbird on January 4, 2019.

COVID-19 means the disease caused by the coronavirus called SARS-CoV-2 and the related worldwide outbreak thereof, which was declared to be a pandemic by the World Health Organization on March 12, 2020.

CPTPP means the Comprehensive and Progressive Agreement for Trans-Pacific Partnership.

CSA means the Canadian Securities Administrators.

CSA 51-324 means Staff Notice 51-324 – Glossary to National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators*.

CUKTCA means the Canada-United Kingdom Trade Continuity Agreement.

DCE&T means drilling, completion, equip and tie-in costs related to a well.

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

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

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

development costs means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil, NGLs 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:

- gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, natural gas lines and power lines, to the extent necessary in developing the reserves;
- drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
- 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
- provide improved recovery systems.

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

Directive 013 means *Directive 013: Suspension Requirements for Wells*.

Directive 060 means *Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting*.

Directive 067 means *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*.

DRIPA means the *Declaration on the Rights of Indigenous Peoples Act*.

EDC Letter of Credit Facility means Pipestone Energy's \$22.5 million unsecured letter of credit facility under Export Development Canada's performance security guarantee program.

Enbridge means Enbridge Inc.

ESG means environmental, social and governance.

ESTMA means the federal governments *Extractive Sector Transparency Measures Act*.

exploratory well means a well that is not a development well, a service well or a stratigraphic test well.

Federal Methane Regulations means the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*.

field means a defined geographical area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

forward-looking statements means forward- looking information and statements.

forecast prices and costs means future prices and costs that are:

- generally acceptable as being a reasonable outlook of the future; and
- if and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in the paragraph above.

formation means a layer of rock which has distinct characteristics that differ from nearby rock.

Fourth Amended and Restated Credit Agreement means the credit agreement dated June 12, 2020 and amendments thereto on November 30, 2022 between the Company and National Bank of Canada, as administrative agent, in respect of the RBL.

Fuel Charge means the regulatory fuel charge implemented under the GGPPA.

G7 means the Group of Seven nations including Canada, France, Germany, Italy, Japan, the United Kingdom and the United States.

GAAP means generally accepted accounting principles.

GGPPA means the *Greenhouse Gas Pollution Pricing Act*.

GHG means greenhouse gases.

GIC means the Governor in Council.

GMT Capital means GMT Capital Corp.

GMT Exploration means GMT Exploration Company LLC.

gross means:

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

HEHE Plan means the Healthy Environment and a Healthy Economy Plan implemented by the Government of Canada.

horizontal drilling means a drilling technique used in certain formations where a well is drilled vertically to a certain depth, after which the drill path builds to 90 degrees until it is in the target formation and continues horizontally for a certain distance.

IA Agency means the Impact Assessment Agency of Canada.

IAA means the *Impact Assessment Act*.

IFRS means the International Financial Reporting Standards as issued by the International Accounting Standards Board and implemented in Canada through the Accounting Recommendations in the Chartered Professional Accountants of Canada Handbook.

Implementation Agreement means the Blueberry River First Nation Implementation Agreement between the Government of British Columbia and the BRFN.

Investors means Riverstone, GMT Capital and GMT Exploration.

IOGA means the *Indian Oil and Gas Act*.

IWCP means the Inactive Well Compliance Program.

Keyera means Keyera Corp. and its affiliates.

Keyera Wapiti Gas Plant means Keyera's 300 MMcf/d gas processing facility, located 60 kilometers southwest of Grande Prairie, Alberta.

Line 3 Replacement means Enbridge's Line 3 replacement project from Hardisty, Alberta, to Superior, Wisconsin.

Liquidation Preference means the Convertible Preferred Shares' initial liquidation preference of \$70 million, equivalent to 70,000 Convertible Preferred Shares.

liquids means oil, condensate and other NGLs.

LMSAA means *The Liabilities Management Statutes Amendment Act*.

McDaniel means McDaniel & Associates Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

McDaniel Reserves Report means the report prepared by McDaniel dated February 17, 2022 evaluating the tight oil, shale gas and NGLs reserves attributable to certain of the assets of the Company as at December 31, 2021. The related Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor, and Report of Management and Directors on Oil and Gas Disclosure, are attached hereto as Appendices "A" and "B", respectively.

Modernized Framework means the modernized Crown royalty framework adopted by the Government of Alberta.

"Modernized IOGA" means *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA.

Montney means the Montney formation, a stratigraphic zone in the Western Canadian Sedimentary Basin.

NAFTA means the North American Free Trade Agreement.

Nationwide Permit 12 means the national permit for water crossings in the United States.

natural gas liquids or **NGLs** means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

NCIB means normal course issuer bid.

NEB means the National Energy Board.

net means:

- in relation to the Company's interest in production or reserves, the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;
- in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and 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.

net acres means the percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

NGO means non-governmental organization.

NGTL means the NOVA's natural gas gathering and transportation system in Alberta and northeastern British Columbia.

NI 51-101 means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators*.

NOVA means NOVA Gas Transmission Ltd.

OBPS means the output-based pricing system for large industry implemented under the GGPPA.

OGCA means the Oil and Gas Conservation Act.

Old Framework means the previous royalty framework implemented by the Government of Alberta.

OPEC means the Organization of the Petroleum Exporting Countries.

OPEC+ means OPEC plus certain other oil-exporting countries, including Russia.

Operating Line means a \$30 million bi-lateral operating facility forming part of the RBL.

Orphan Fund means the orphan fund created by the AER.

OWA means the Orphan Well Association.

Pan-Canadian Framework means the Pan-Canadian Framework on Clean Growth and Climate Change.

Pembina means Pembina Pipeline Corporation, Pembina Gas Services Limited Partnership and/or their respective affiliates, as is appropriate in the context.

Pembina Pipeline means the Pembina Peace natural gas liquids and condensate pipeline located in Alberta.

Pieridae means Pieridae Energy Ltd.

Pipestone Energy, we, us, our or the Company means Pipestone Energy Corporation.

Pipestone Area means the Pipestone Montney area situated southwest of Grande Prairie in Northwest Alberta.

Pipestone Project means the Company's project focused on the exploration for, development and production of oil and natural gas liquids (including condensate, butane and propane), herein collectively referenced as "liquids", as well as natural gas from its large contiguous land position of over 141 net sections in the condensate Fairway of the Pipestone Montney area situated southwest of Grand Prairie in northwest Alberta.

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

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

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

PSG means Export Development Canada's performance security guarantee program.

RBL means the Company's \$280 million Reserve-Based Loan. See "*Description of Capital Structure – Reserve-Based Loan*" section

below for more details.

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

reservoir means a subsurface rock unit that contains an accumulation of petroleum.

RFPP means a Request for Full Project Proposals for Carbon Sequestration Hubs.

Riverstone means collectively, Riverstone V REL CNOR LP and Riverstone Pipestone LP.

Riverstone Nomination Agreement means the nomination agreement between Pipestone Energy and Riverstone Pipestone LP dated September 15, 2020.

SCC means the Supreme Court of Canada.

Second Amended and Restated Credit Agreement means the credit agreement dated June 12, 2020 and amendments thereto on July 20, 2020 between the Company and National Bank of Canada as administrative agent that outlines the specific terms and conditions of the RBL.

SEDAR means the System for Electronic Document Analysis and Retrieval maintained by the Canadian Securities Administrators.

Seismic Protocol Regions means the seismic protocols in place for Fox Creed, Red Deer and Brazeau.

Senior Facility means the \$250 million syndicated borrowing facility forming part of the RBL.

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

shale gas is defined by NI 51-101 as natural gas (i) contained in dense organic-rich rocks, including low permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay minerals, and (b) that usually requires the use of hydraulic fracturing to achieve economic production rates. The Company has also categorized what is typically referred to as "tight gas" under "shale gas" since "tight gas" is not defined in NI 51-101. This includes natural gas that is contained in low-permeability shales, siltstones and carbonates, in which the natural gas is primarily contained in microscopic pore spaces that are poorly connected to one another, which typically requires the use of hydraulic fracturing to achieve economic production rates.

Sour Gas means natural gas containing H₂S in quantities greater than 100 ppm.

Sovereignty Act means Bill 1: The Alberta Sovereignty Within a United Canada Act.

stratigraphic test well means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as:

- "exploratory type" if not drilled into a proved property; or

- "development type" if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

SUPPR means the *Single-use Plastics Prohibitions Regulations*.

Syndicated Facility means a \$195 million syndicated revolving facility forming part of the RBL.

TC Energy means TC Energy Corporation and affiliates.

TCPL means the 14,114 km (8,770 mile) pipeline system that is owned and operated by TC Energy, which carries natural gas from the Western Canadian Sedimentary Basin to Ontario and beyond.

Third Amended and Restated Credit Agreement means the credit agreement dated June 12, 2020 and amendments thereto on April 30, 2021 between the Company and National Bank of Canada as administrative agent that outlines the specific terms and conditions of the RBL.

Tidewater means Tidewater Midstream and Infrastructure Ltd.

Tidewater Dimsdale Gas Storage Facility means Tidewater's Dimsdale Patty A natural gas storage reservoir at its Pipestone Gas Storage Facility.

Tidewater Pipestone Gas Plant means Tidewater's 100 MMcf/d sour, deep-cut Montney gas plant in the Pipestone Area.

TIER means the *Technology Innovation and Emissions Reduction Regulation*.

tight oil means crude oil contained in dense organic-rich rocks, including low permeability shales, siltstones and carbonates, in which the natural gas is primarily contained in microscopic pore spaces that are poorly connected to one another and that usually requires the use of hydraulic fracturing to achieve economic production rates.

TPP means the Trans-Pacific Partnership.

Treaty 8 Nations means four of the Treaty 8 First Nations, including the Fort Nelson, Saulteau, Halfway River and Doig River.

TSX means the Toronto Stock Exchange.

TSXV means the TSX Venture Exchange.

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

UNDRIP means United Nations Declaration of the Rights of Indigenous Peoples.

UNDRIP Act means United Nations Declaration on the Rights of Indigenous Peoples Act.

UNFCCC means the United Nations Framework Convention on Climate Change.

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

USMCA means the United States Mexico Canada Agreement.

Veresen Hythe Gas Plant means Veresen Midstream's 570 MMcf/d gas processing facility, located northwest of Grande Prairie near Hythe, AB.

Veresen Midstream means Veresen Midstream LP.

Wapiti means the "Wapiti" area of Alberta, Canada.

working interest means the right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Conventions

Certain terms used herein are defined in the "*Selected Terms*". Certain other terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "\$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

Abbreviations			
Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls	barrels	MMcf	million cubic feet
Bcf	billion cubic feet	Mcf/d	thousand cubic feet per day
Bcf/d	Billion cubic feet per day	MMcf/d	million cubic feet per day
bbls/d	barrels per day	MMbtu	million British Thermal Units
Mbbls	thousand barrels	GJ	gigajoule
NGLs	natural gas liquids	GJ/d	Gigajoule per day

Other	
AECO	The pricing point for gas transacted on TC Energy's Alberta Transmission System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
Chicago Citygate	The Chicago Index Futures natural gas price
MBoe	thousand barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
\$000s	thousands of dollars
\$MM	millions of dollars

Conversion

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.289

feet	metres	0.305
metres	feet	3.281
miles	kilometers	1.609
kilometers	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

Forward-Looking Information & Statements

This Annual Information Form ("AIF") contains forward-looking statements. These statements relate to future events or future performance of the Company. All statements other than statements of present or historical fact are forward-looking statements. When used in this AIF, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "estimate", "predict", "seek", "propose", "expect", "potential", "continue", and similar expressions, are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties, and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Pipestone Energy believes that the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this AIF should not be unduly relied upon. Moreover, Pipestone Energy does not assume responsibility for the accuracy and completeness of the forward-looking statements. Pipestone Energy's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Pipestone Energy will derive therefrom. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this AIF as intended, planned, anticipated, believed, estimated, or expected.

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Forward-looking statements are based on the estimates and opinions of our management at the time the statements were made. In addition, forward-looking statements may include statements attributable to third party industry sources. There can be no assurance that the plans, intentions or expectations upon which such forward-looking statements are based will occur.

In addition to the forward-looking statements identified above, this AIF contains forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- prospective future drilling locations;
- expectations of growing production, generating significant free cash flow and de-leveraging the business;
- short-term development plans;
- the expectation that the water handling and disposal facility at the Company's 15-25 pad-site will provide additional flexibility and production capacity and will lower future operating costs;
- the Company's dividend policy, the funding of such dividends, the amounts expected to be paid under the policy in the future and the anticipated timing of payment of such dividends;
- expectations regarding the Company's intention to acquire Common Shares pursuant to the NCIB and any future substantial issuer bid;
- the future development and growth potential of our assets;
- the Company's intention to develop its proved undeveloped reserves and timing thereof;
- the expectation that the Company's proved undeveloped reserves will be the primary driver of production and cash flow over the next five years;
- expectations regarding pace of development of the Company's probable undeveloped reserves and related capital spending;

- future well performance and related well economics;
- expectations of future production rates, volumes and product mixes;
- projected development and other costs and plans and objectives;
- the quarterly dividend rate;
- our capital expenditure program, the timing of expenditures and the sources of funding;
- our access to credit facilities, ability to raise capital and financial flexibility;
- our access to third-party infrastructure and ability to sell our products into various North American markets;
- future commodity prices;
- abandonment and reclamation costs;
- production estimates;
- carbon pricing;
- supply and demand for oil, natural gas and natural gas liquids;
- the taxability of the Company; and
- expected royalty rates and the anticipated benefits of royalty incentive programs.

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

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this AIF. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct.

Some additional risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- volatility of commodity prices and differentials;
- anticipated production levels;
- declining economic, business or industry conditions;
- the inability to access sufficient capital from internal and external sources and the cost of capital;
- weakness in the oil and natural gas industry;
- the marketability of production and demand for the Company's products;
- uncertainty in public perception of oil and natural gas development;
- failure to obtain industry partner, regulatory or other third party consents and approvals when required;
- political uncertainty;
- the impact of geopolitical actions, including war and terrorism;
- liabilities inherent in oil and natural gas operations;
- lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines;
- stock market volatility;
- a decrease or elimination of the payment of dividends by the Company as a result of Board determination or restrictions under applicable agreements or corporate laws;
- risks associated with significant shareholder control of the Company;
- incorrect assessments of the value of acquisitions;
- operational dependence on third parties;
- project risks;
- environmental risks;
- governmental regulation and regulatory changes;
- imprecision of reserve and resource estimates;
- competition from other industry participants;
- changes in our credit ratings;

- risks associated with our information technology systems and in particular cyber-security;
- our ability to successfully implement new technologies into our operations;
- alternatives to and changing demand for petroleum products;
- geological, technical, drilling and processing problems;
- applicable royalty rates and tax laws;
- climate change regulation and carbon pricing;
- liability management programs;
- potential litigation;
- fluctuation in foreign exchange or interest rates;
- fluctuations in the cost of borrowing;
- risks associated with refinancing our Third Amended and Restated Credit Agreement and our level of indebtedness;
- risks associated with our hedging activities;
- the lack of availability of qualified personnel or management or oilfield services;
- unforeseen title claims or defects;
- our ability to satisfy our obligations under our firm commitment transportation and processing arrangements;
- ongoing impacts of COVID-19 including but not limited to impacts on field activity levels, health and safety considerations and restrictions which may impact the ability of the Company to carry on business as planned;
- general economic and industry conditions; and
- the other factors discussed under "*Risk Factors*".

With respect to forward-looking statements contained in this AIF, we have made assumptions regarding, among other things: the timing of obtaining regulatory approvals; commodity prices and royalty regimes; the absence of significant adverse changes to interest rates and tax laws; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; demand for products and cost of operations; the impact of increasing competition; conditions in general economic and financial markets and business conditions; the Company's ability to market production of oil and natural gas successfully to customers; access to capital; availability of drilling and related equipment; effects of regulation by governmental agencies; the absence of significant adverse changes to political and social stability; royalty rates and future operating costs. We have included the above summary of assumptions and risks related to forward-looking statements provided in this AIF in order to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes. **The information contained in this AIF, including the documents incorporated by reference or referred to herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this AIF are made as of the date of this AIF and we undertake no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by Applicable Securities Laws.

General Advisories

Information contained in or otherwise accessible through the Company's website at www.pipestonecorp.com or through any

other website referred to on Pipestone Energy's website or in this AIF does not form a part of this AIF and is not incorporated by reference herein.

Oil and Gas Advisories

Oil and Gas Metrics

Pipestone Energy has adopted the standard of 6 Mcf:1 bbl when converting natural gas to oil equivalent. Condensate and other NGLs are converted to oil equivalent at a ratio of 1 bbl:1 bbl. The use of boe as a measure may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is an approximation based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the Company's sales point. Given the value ratio based on the current price of oil as compared to natural gas and NGLs are significantly different from the energy equivalency of 6 Mcf:1 bbl and 1 bbl:1 bbl, respectively, utilizing a conversion ratio at 6 Mcf:1 bbl for natural gas and 1 bbl:1 bbl for NGLs may be misleading as an indication of value.

The discounted and undiscounted net present value of future net revenues attributable to Pipestone Energy's reserves do not represent the fair market value of Pipestone Energy's reserves. There is no assurance that the forecast prices and costs assumptions applied by Pipestone Energy's independent reserves evaluator in evaluating the reserves of Pipestone Energy will be attained and variances could be material. The estimates of Pipestone Energy's tight oil, NGL, and shale gas reserves provided in this AIF or otherwise referred to in this AIF are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual tight oil, NGL, and shale gas reserves may be greater than or less than the estimates provided in this AIF or otherwise referred to in this AIF, and the difference may be material.

Analogous Information

Certain information in this AIF may constitute "analogous information" within the meaning of NI 51-101, including information relating to areas, wells or operations that are in geographical proximity to or believed to be on-trend with lands held by Pipestone Energy and production information in respect of wells that are believed to be on trend with Pipestone Energy's properties. Such information has been obtained from governmental or other public sources, regulatory agencies or other industry participants that are independent of Pipestone Energy. Pipestone Energy does not know whether any such information contained herein that constitutes "analogous information" was prepared in accordance with the COGE Handbook or by a qualified reserves evaluator or auditor under NI 51-101, as applicable, and cannot verify its accuracy. While believed to be reliable, third party data relied upon by Pipestone Energy may be in error.

Management believes such information may be relevant to Pipestone Energy's efforts to understand and predict reservoir characteristics of properties in which Pipestone Energy may hold or intend to acquire an interest, and it is presented to help demonstrate the basis for Pipestone Energy's business plans and strategies. There is, however, no assurance that the qualities, characteristics or results suggested by or inferred from analogous information are or will be similar to or otherwise representative of the qualities or characteristics of properties in which Pipestone Energy has or intends to acquire an interest or the results that Pipestone Energy may achieve or realize from any operations thereon. Such information is not, and should not be construed or relied upon as, an estimate or predictor of resource potential or future production levels.

Non-GAAP Measures

This AIF contains references to "operating netback", "adjusted funds flow from operations", "EBITDA" and "free cash flow" which are terms commonly used in the oil and natural gas industry but without any standardized meaning or method of calculation prescribed by IFRS or applicable law. Accordingly, Pipestone Energy's determination of this metric may not be comparable to similar measures presented by other issuers.

"Operating netback" is calculated on either a total dollar or per-unit-of-production basis and is determined by deducting royalties, operating and transportation expenses from liquids and natural gas sales adjusted for realized gains/losses on commodity risk management contracts. Operating netback is a common metric used in the oil and natural gas industry and is used by Company management to measure operating results on a per boe basis to better analyze and compare performance against prior periods, as well as formulate comparisons against peers.

"Adjusted funds flow from operations" is calculated as cash from operating activities before changes in non-cash working capital and decommissioning provision costs incurred, which is a measure that is not defined under IFRS. Adjusted funds flow from operations should not be considered an alternative to, or more meaningful than, cash from operating activities, income (loss) or other measures determined in accordance with IFRS as an indicator of the Company's performance. Management uses adjusted funds flow from operations to analyze operating performance and leverage and believes it is a useful supplemental measure as it provides an indication of the funds generated by Pipestone Energy's principal business activities prior to consideration of changes in working capital.

"EBITDA" is calculated as the Company's income (loss) before interest, taxes, depreciation and amortization are deducted. Management uses EBITDA to analyze operating performance and believes it is a useful supplemental measure as it provides an indication of the operating profit generated by Pipestone Energy's principal business activities prior to consideration of interest, taxes, depreciation and amortization. EBITDA is also used by the Company's lenders to determine applicable borrowing rates on the RBL.

"Free cash flow" equals cash from operating activities plus the change in non-cash working capital less capital expenditures. Free cash flow should not be considered an alternative to, or more meaningful than, cash from operating activities as determined in accordance with IFRS as an indicator of financial performance. Free cash flow is presented to assist management and investors in analyzing operating performance by the business and how much cash flow is available for deleveraging and / or shareholder returns in the stated period after capital expenditures have been incurred.

Additional information relating to each non-GAAP measure and non-GAAP ratio disclosed in this AIF, including disclosure of the composition of the non-GAAP measures and an explanation of how each non-GAAP measure provides useful information to investors, is contained in the "*Non-GAAP measures*" section of management's discussion and analysis of the Company dated March 8, 2023 for the year ended December 31, 2022, which section is incorporated by reference in this AIF. Management's discussion and analysis of the Company for the year ended December 31, 2022 is available on SEDAR at www.sedar.com under Pipestone Energy's company profile.

Corporate Structure

Pipestone Energy trades on the TSX under the ticker symbol PIPE and is organized under the ABCA.

Pipestone Energy's head office is located at Suite 3700, 888 3rd Street S.W., Calgary, Alberta, T2P 5C5. Pipestone Energy's registered office is located at Suite 4000, 421 – 7th Avenue SW, Calgary, Alberta, T2P 4K9.

Pipestone Energy does not have any material subsidiaries at December 31, 2022.

General Development of the Business

The following discussion covers Pipestone Energy's development of its business over the past three years.

Development

Pipestone Energy's development plans in 2020, 2021 and 2022 have focused on the continued exploration and exploitation of its condensate-rich Montney asset. This development activity has been primarily focused on the Company's North-South infrastructure "spine" along the western border of its acreages with the Company beginning to step-out to the eastern portion of

its land base in 2021 and 2022.

2020

Pipestone Energy drilled and rig-released a total of 15 wells across its 6-30, 3-12 and 8-15 pad-sites during 2020. The Company has continued to achieve drilling and completion cost reductions while extending the average lateral length of its wells. The 3 wells located at the 8-15 pad were drilled in late 2020 at an average lateral length of 3,094 metres for a cost of \$2.2 million per well.

During 2020, the Company completed a total of 12 wells across its 6-30 and 3-12 pad-sites. In December 2020 the 6 wells at the 3-12 pad-site were successfully completed for an average cost of \$3.1 million per well (2,650 metre lateral length & 2.4 tonnes per metre proppant loading), bringing the average DCE&T cost, including the pad-site facilities, to \$5.4 million per well for this pad. The DCE&T costs achieved at the 3-12 pad are in-line with Pipestone Energy's previous pacesetter results set at the 6 well 6-30 pad.

By the end of 2020, Pipestone Energy successfully brought 20 additional wells on production north of the Wapiti River. The Company achieved its full year production guidance range of 15,000 – 16,000 boe/d for 2020, with an actual production rate of 15,570 boe/d in 2020. 2020 exit production was comprised of a total of 49 wells, with 40 wells north of the Wapiti River, 8 wells south of the Wapiti River and 1 net (5 gross) non-operated wells on the Company's eastern lands. The Company was also within its revised capital guidance for 2020 of \$108.0 million, with total capital expenditures of \$102.0 million incurred, excluding capitalized general and administrative expenses. Pipestone Energy reported \$136.0 million of liquids and natural gas sales and generated \$40.5 million of adjusted funds flow from operations⁽¹⁾ for the year ended December 31, 2020.

2021

Pipestone Energy drilled and rig-released a total of 30 wells across its 6-13, 15-25, 6-24, 14-4, 2-31 and 6-30 pad-sites during 2021. Three step-out wells, including one Lower Montney well, were drilled from the 14-4 pad which is located to the east of the Company's existing development activity. These wells have further delineated the Company's land base.

During 2021, the Company completed a total of 24 wells across its 8-15, 15-25, 6-24, 14-4 and 6-13 pad-sites.

Pipestone Energy achieved its lowest all-in DCE&T costs to date on the 3 additional wells, as part of the second phase of operations, at the 6-13 pad. The average DCE&T cost per well was \$4.9 million, comprised of \$1.7 million on drilling, \$2.8 million on completions and \$0.4 million on equip and tie-in. These wells were drilled with a lateral length of 2,417 metres and were completed with proppant intensity of 2.5 tonnes per metre.

By the end of 2021, Pipestone Energy successfully brought 27 additional wells on production north of the Wapiti River. The Company achieved its full year production guidance range of 24,000 – 26,000 boe/d for 2021, with an actual production rate of 24,584 boe/d in 2021. Total capital expenditures for 2021 were \$183.6 million, excluding capitalized general and administrative expenses. Pipestone Energy reported \$391.3 million of liquids and natural gas sales and generated \$166.4 million of adjusted funds flow from operations⁽¹⁾ for the year ended December 31, 2021.

2022

Pipestone Energy drilled and rig-released a total of 26.5 net wells (28 gross wells) across its 2-25, 9-14, 2-32, 14-19, 11-5, 13-9 and 2-31 pad-sites during 2022.

During 2022, the Company completed a total of 29.5 net wells (31 gross wells) across its 2-31, 6-30, 2-25, 12-36, 9-14, 2-32, 14-19 and 13-9 pad-sites. The completion of the Company's standing Montney exploration well on the 12-36 pad-site, located approximately 13km east of the Company's nearest producing wells, was an important test for demonstrating the resource extent

⁽¹⁾ See "Non-GAAP measures".

of the Pipestone Montney asset. The well was completed using a plug and perf style completion with proppant loading of 2.5 tonnes per metre on a short 1,900 metre lateral section.

In 2022, Pipestone Energy successfully brought 21 additional operated wells on production, with three additional non-operated wells at the northernmost 13-9 pad-site brought on-stream in the fourth quarter of 2022 which also contributed to production volumes. The Company achieved its full year production guidance range of 31,000 - 33,000 boe/d for 2022, with an actual production rate of 31,090 boe/d in 2022.

Total capital expenditures for 2022 were \$242.4 million, excluding capitalized general and administrative expenses. The Company reported \$723.8 million of liquids and natural gas sales, \$383.0 million of adjusted funds flow from operations ⁽¹⁾ and generated free cash flow ⁽¹⁾ of \$137.2 million for the year ended December 31, 2022.

Infrastructure

2020

In January 2020, the Company exercised its option to secure an additional 30 MMcf/day of Priority 1 natural gas gathering, compression and processing capacity at the Keyera Wapiti Gas Plant. The additional compressor required to expand the existing 8-15 compressor station was installed by Keyera and came on-stream in the fourth quarter of 2020. Following the installation, Pipestone Energy has a total of 90 MMcf/d of Priority 1 access to the Keyera Wapiti Gas Plant in addition to the 30 MMcf/d of Priority 1 access through the Tidewater Pipestone Gas Plant for a total of 120 MMcf/d of Priority 1 access. Pipestone Energy's take-or-pay commitment with Keyera increased from 48 MMcf/d to 60 MMcf/d starting in April 2021, with subsequent increases to 72 MMcf/d beginning in January 2022 and 80 MMcf/d in April 2022 onward.

In 2020 an unplanned outage occurred at the Keyera Wapiti Gas Plant, which spanned 38 days from August 17th to September 24th.

In December 2020, the Company entered into an agreement with Veresen Midstream for an additional 50 MMcf/d of gas processing capacity at the Veresen Hythe Gas Plant, as well as ancillary transportation and fractionation services with Pembina to support anticipated production growth in 2021 and beyond.

The gas processing arrangement with Veresen Midstream secures 25 MMcf/d of firm priority 1 service at the Veresen Hythe Gas Plant, with an additional 25 MMcf/d of interruptible service for a term of approximately 10 years. In addition, Veresen Midstream funded the construction of a new gathering pipeline from Pipestone Energy's 6-30 pad to its 16-28 compressor station and battery, as well as additional facilities on the 6-30 pad required to accommodate up to 50 MMcf/d of raw gas and associated liquids. Firm service commenced in November 2021, which coincided with the completion of the new gathering pipeline. Pipestone Energy designed, constructed and operates these additional facilities upon commissioning.

The Company's arrangement with Veresen Midstream included a 12-month ramp up period with no associated take-or-pay commitment, which ended on September 30, 2022. Beginning on October 1, 2022 and ending on February 28, 2033, the Company has take-or-pay volumes of 22.5 MMcf/d. The Company expects to be able to access its interruptible capacity as required through the contract term.

The Company has also secured liquids transportation and fractionation capacity with Pembina with its volume commitments proportionate to its firm gas commitment at the Veresen Hythe Gas Plant. Firm service commenced in November 2021 and take-or-pay obligations began in October 2022. Pipestone Energy also secured 10 MMcf/d of natural gas transportation from the Veresen Hythe Gas Plant outlet to Chicago on the Alliance Pipeline, which was incremental to its existing capacity of 5 MMcf/d for a total capacity of 15 MMcf/d available through the Alliance Pipeline.

2021

In early November 2021, Pipestone Energy completed the construction and commissioning of the Veresen Midstream-owned and Pipestone Energy-operated 12" gathering pipeline and 6-30 battery. This infrastructure ties Pipestone Energy's production into the 16-28 compressor station and ultimately to the Veresen Hythe Gas Plant. The Company continued to ramp-up its production volumes to exit the year with November and December 2021 production averaging 30,809 boe/d.

2022

In April 2022, the Company's Alliance Pipeline capacity was expanded from 15 MMcf/d to approximately 30 MMcf/d.

In October 2022, a Pipestone Energy funded expansion to the existing Keyera 8-15 compressor station was completed. Following the installation of a fourth compressor, the capacity of the 8-15 compressor station increased from 90 MMcf/d to 120 MMcf/d, earning the Company a 15.9% working interest in the entire facility and designation as permanent operator of record.

In October 2022, the Company also completed the commissioning of a water handling and disposal facility at its 15-25 pad-site, expanding the Company's in-field water handling capacity by approximately 15,000 bbls/d. Pipestone Energy partnered with Catapult Water Midstream and Topaz Energy Corp. to fund the facility, which earned each partner a 49.5% working interest, while Pipestone Energy retains a 1% working interest and operatorship. This project is expected to provide additional flexibility and production capacity and is also expected to lower future operating costs. The arrangement carries a fixed monthly capital fee and an option to expand the water handling infrastructure in the future.

Financings

2020

On June 12, 2020, the Company announced that it had successfully redetermined and amended its existing RBL credit agreement with its syndicate of banks, maintaining its credit capacity at \$225 million. As part of the Second Amended and Restated Credit Agreement, the Company's \$195 million Syndicated Facility was replaced with a \$125 million Senior Facility and a \$70 million Additional Facility, with the Additional Facility carrying higher borrowing rates. The Company was also restricted from spending more than \$65 million of capital in 2020 without unanimous consent from its banking syndicate as a temporary provision, to terminate at the next redetermination, which was originally scheduled for November 2020.

In accordance with an additional amendment executed on July 20, 2020, contingent on the closing of the Convertible Preferred Share Financing, the banking syndicate agreed to forgo the November 2020 borrowing base review with the next redetermination re-scheduled for May 2021. In addition, the previously imposed capital spending restrictions from the June 2020 redetermination were removed, and Pipestone Energy agreed to implement a hedging program with respect to expected condensate volumes through calendar 2021.

On July 16, 2020, Pipestone Energy closed a \$15 million unsecured letter of credit facility under Export Development Canada's PSG program. The Company subsequently transferred \$14.3 million of letters of credit outstanding from its RBL to the letter of credit facility. Letters of credit issued under the letter of credit facility do not impact Pipestone Energy's borrowing capacity under the RBL and as such provides the Company with additional liquidity.

On August 5, 2020, Pipestone Energy announced that it had entered into subscription agreements with Riverstone V EMEA Holdings Cooperatief U.A., subsequently assigned to Riverstone Pipestone LP and certain hedge fund and private client accounts of GMT Capital and GMT Exploration in respect of the Convertible Preferred Share Financing. The Convertible Preferred Share Financing closed on September 17, 2020, with proceeds to Pipestone Energy of approximately \$67 million, net of transaction

costs.

As part of the Convertible Preferred Share Financing, the Investors acquired Convertible Preferred Shares in the Company with the Liquidation Preference. The Convertible Preferred Shares had a Conversion Price of \$0.85 per Common Share and a term of five years. The Convertible Preferred Shares were sold at a price of \$970 per share and entitle the Investors to an annual dividend of 6.5% per year payable quarterly in-kind, or in cash after 2 years from issuance, at the sole option of Pipestone Energy.

The Convertible Preferred Shares were, subject to certain conditions, convertible into Common Shares at a conversion price of \$0.85 per Common Share, subject to customary adjustments. After two years, if among other things, the closing price of the Common Shares was above 200% of the Conversion Price for 20 days over a 30-day trading period and Pipestone Energy had an effective shelf prospectus covering resales of the underlying Common Shares to be received upon conversion of the Convertible Preferred Shares, the Convertible Preferred Shares would automatically convert into Common Shares at the Conversion Price. The Conversion Price represented a 70% premium to the 30-day volume weighted average trading price of the Common Shares on August 4, 2020, the last trading day prior to entering into the subscription agreements. Holders of the Convertible Preferred Shares were entitled to vote on all shareholder matters alongside existing holders of the Common Shares on a diluted basis assuming, conversion of the Convertible Preferred Shares. Post the Convertible Preferred Share Financing, the Convertible Preferred Shares represented approximately 30% of Pipestone Energy's pro forma shares outstanding on a fully diluted basis. After the five year term, the Convertible Preferred Shares would automatically convert into Common Shares at either the Conversion Price, if the Common Shares were trading at a price in excess of the Conversion Price or, otherwise, at a price based on the previous 20-day volume weighted average share price multiplied by 95%.

While the Convertible Preferred Shares were not listed on any stock exchange, the Company reserved the underlying Common Shares issuable upon conversion of the Convertible Preferred Shares for listing on the TSX (previously on the TSXV at the time of the transaction).

TSX Graduation

On December 16, 2020, Pipestone Energy completed its up-listing from the TSXV and began trading on the TSX. The Company's graduation to the TSX marked an important milestone in the continued growth and evolution of the business.

2021

On April 30, 2021, Pipestone Energy renewed and amended its existing RBL credit agreement with its syndicate of banks maintaining its borrowing capacity at \$225 million. Upon renewal, the Company's previous \$70 million Additional Facility, established in 2020, was converted back into fully conforming capacity available under the Senior Facility. At that time, the RBL was comprised of a \$195 million Senior Facility and a \$30 million Operating Line. The elimination of the Additional Facility reduced Pipestone Energy's annual borrowing cost by approximately 2.0% on the amounts previously drawn on the Additional Facility. In addition, the Senior Facility and Operating Line pricing was reduced by 0.25% across the pricing grid, which further reduced the Company's borrowing cost on all amounts drawn post April 30, 2021.

On October 29, 2021, the Company redetermined and upsized its RBL. The total borrowing capacity of the RBL was increased from \$225 million to \$280 million, with the Senior Facility capacity being increased by \$55 million to \$250 million, and the Operating Line remaining unchanged at \$30 million. The covenants of the credit facility were also amended to allow for permitted distributions which provided the Company with flexibility under certain circumstances to return capital to shareholders.

On November 22, 2021, the Company announced the approval by the TSX of its notice to commence an NCIB to purchase, for cancellation, a maximum of 9,598,347 Common Shares, representing 5% of its issued and outstanding Common Shares as at November 12, 2021. The inaugural NCIB commenced on November 25, 2021 and expired on November 24, 2022. The Company repurchased 9,598,347 Common Shares under the inaugural NCIB at an average purchase price of \$4.44 per Common Share.

2022

On January 20, 2022, the Company announced the independent certification of all its production from the Pipestone Wembley asset under the Equitable Origin EO100™ Standard for Responsible Energy Development. Pipestone Energy's produced natural gas was certified against five principles of the EO100™ Standard including corporate governance and ethics; social impacts, human rights and community engagement; Indigenous Peoples' rights; occupational health and safety and fair labour standards; and environmental impacts, biodiversity and climate change.

On May 10, 2022, the Company redetermined its RBL. While the total borrowing capacity of \$280 million and rates remain unchanged, the covenants of the credit facility were amended to permit additional distributions, providing the Company with further flexibility under certain circumstances to return capital to shareholders.

On September 15, 2022, the Company announced its inclusion in the TSX's TSX30 list, a flagship program recognizing the 30 top-performing TSX stocks over a three-year period based on dividend-adjusted share price performance.

On September 30, 2022, all of the holders of the Convertible Preferred Shares exercised their right to the voluntary early conversion of the outstanding Convertible Preferred Shares. As at September 30, 2022, the date of the conversion notices, the Convertible Preferred Shares had a liquidation preference, including accruals of the dividends paid in-kind on the Convertible Preferred Shares, of \$79,850,406, and were converted into an aggregate of 93,941,655 Common Shares on October 5, 2022. No dividends were declared or paid on the Convertible Preferred Shares while they were outstanding. Following the conversion of the Convertible Preferred Shares, Pipestone Energy had 279,442,517 Common Shares outstanding.

On November 23, 2022, the Company announced the approval by the TSX of its notice to renew its NCIB to purchase, for cancellation, a maximum of 13,936,907 Common Shares, representing 5% of its issued and outstanding Common Shares as at November 14, 2022. The Common Shares can be repurchased by Pipestone Energy in open market transactions on the TSX and other alternative trading platforms in Canada over a 12-month period. The renewed NCIB commenced on November 25, 2022 and is due to expire no later than November 24, 2023. As of February 28, 2023, the Company had repurchased nil Common Shares under the renewed NCIB.

On November 23, 2022, the Board established a quarterly dividend of \$0.030 per Common Share, commencing in the first quarter of 2023. Additionally, the Company announced its intention to launch a substantial issuer bid for up to \$50 million in the first quarter of 2023.

On November 30, 2022, the Company redetermined its RBL once again with all terms remaining unchanged. The next redetermination of the borrowing base and revolving period of the RBL are scheduled for the end of May 2023, with an additional one-year term out period thereafter.

Management

Pipestone Energy's management team currently consists of Paul Wanklyn, President and CEO; Dustin Hoffman, Chief Operating Officer; Craig Nieboer, Chief Financial Officer; and Dan van Kessel, Vice President, Corporate Development.

General Description of the Business

Summary Description of the Business

Pipestone Energy is an oil and gas company focused on the exploration for, and development and production of, oil and NGLs (including condensate, butane and propane) herein collectively referenced as "liquids" and natural gas in the Condensate Fairway of the Pipestone Montney area, in northwest Alberta. The Company holds a large contiguous land position of over 141 net sections, with a significant development inventory. Pipestone Energy values the partnerships it is developing within the greater

Grande Prairie and Wembley areas and strives to be the best-in class operator within the community.

Key Objectives

Pipestone Energy is an oil and gas exploration and production company focused on developing its large contiguous and condensate rich Montney asset base in the Pipestone Area. Pipestone Energy expects to grow its production, while generating free cash flow² and de-leveraging the business. Pipestone Energy is committed to building long term value for shareholders while maintaining top-decile environmental and operating standards, as well as being an active and contributing member to the communities in which it operates.

Development Focus

Pipestone Energy aims to deliver production and free cash flow⁽²⁾ growth while maintaining a strong balance sheet. The Company is focusing on efficient capital deployment with a measured growth trajectory. The focus of Pipestone Energy's development in the short-term will be concentrated in areas of the acreage with the highest projected liquids content and deliverability, while maximizing efficiencies by taking advantage of existing pads and infrastructure. With the completion of its in-field gathering system in 2019 that is currently capable of handling approximately 40,000 boe/d, Pipestone Energy's development plan will be primarily focused on half-cycle development economics until this capacity is reached, which is anticipated to occur in early 2024.

Infrastructure Arrangements

Pipestone Energy currently has access to four third-party processing facilities which process the majority of the Company's liquids-rich gas production. In fall 2019, Tidewater completed its 100 MMcf/d Tidewater Pipestone Gas Plant with a processing commitment originally contracted to Blackbird. Processing commitments at the Tidewater Pipestone Gas Plant includes preferential access to the Tidewater Dimsdale Gas Storage Facility (if required in excess of transportation commitments). Additionally, in 2019, Keyera completed its first 150 MMcf/d phase of its 300 MMcf/d Keyera Wapiti Gas Plant at Wapiti. The second phase of the Keyera Wapiti Gas Plant was completed in 2020 increasing its capacity to 300 MMcf/d.

In 2019, Pipestone Energy had firm access to 60 MMcf/d of natural gas gathering, compression, and processing through the Keyera Wapiti Gas Plant which began in September 2019. As part of the Keyera Wapiti Gas Plant system, and on behalf of Pipestone Energy, Keyera installed a compression facility (8-15 compressor station) immediately west of Pipestone Energy's 15-14 pad site. In 2020, this capacity was expanded to 90 MMcf/d through the installation of a third compressor at the 8-15 compressor station. In 2022, Pipestone Energy spent approximately \$8 million to increase capacity at the 8-15 compressor station from 90 MMcf/d to 120 MMcf/d, earning the Company a 15.9% working interest in the entire facility and designation as permanent operator of record. As of December 31, 2022, Pipestone Energy has Priority 1 (firm) capacity of 90 MMcf/d and access to 30 MMcf/d of interruptible capacity, with take-or-pay obligations of 80 MMcf/d with an initial term to October 31, 2029 at the Keyera Wapiti Gas Plant.

At the Tidewater Pipestone Gas Plant, Pipestone Energy has firm capacity and take-or-pay obligations of 30 MMcf/d with an initial term to October 31, 2029.

In December 2020, the Company entered into an agreement with Veresen Midstream for an additional 50 MMcf/d of gas processing capacity at the Veresen Hythe Gas Plant, as well as ancillary transportation and fractionation services with Pembina to support anticipated production growth. The gas processing arrangement with Veresen Midstream secures 25 MMcf/d of firm priority 1 service at the Veresen Hythe Gas Plant with an additional 25 MMcf/d of interruptible service for a term of approximately 10 years.

In addition, Veresen Midstream funded the construction of a new gathering pipeline from Pipestone Energy's 6-30 pad to its 16-28 compressor station and battery, as well as additional facilities on the 6-30 pad required to accommodate up to 50 MMcf/d of

² See "Non-GAAP measures".

raw gas and associated liquids. Firm service commenced in November 2021, which coincided with the completion of the new gathering pipeline. Pipestone Energy is the operator of these facilities and the Company has take-or-pay volumes of 22.5 MMcf/d that began on October 1, 2022 and ends on February 28, 2033.

Minor production volumes from legacy Blackbird wells and pad-sites that are located to the south of the Wapiti River are tied-in and processed through the CNRL Gold Creek Plant. Pipestone Energy currently has access to 6 MMcf/d of gas processing capacity on an interruptible basis through the CNRL Gold Creek Plant.

Pipestone Energy has diversified transportation capacity on the TCPL and Alliance Pipeline systems to materially match its processing commitments and growth plans. Pipestone Energy currently holds 109 MMcf/d (sales gas) of firm capacity on the NGTL system. Pipestone Energy also has 30 MMcf/d (sales gas) of long-term firm capacity on the Alliance Pipeline. In addition, Pipestone Energy utilizes short-term seasonal contracts with Alliance, as well as through gas marketing firms, to supplement its long-term firm gas transportation capacity and meet its needs. Transportation arrangements are in place for the delivery of Pipestone Energy's condensate and NGLs volumes into the liquid Edmonton market. Currently the Company has 8,250 bbls/d of firm condensate transportation capacity on the Pembina Pipeline, with additional capacity available on an interruptible basis. The Company also currently has 1,570 bbls/d of firm C3+ transportation capacity on the Pembina Pipeline, with additional capacity available on an interruptible basis.

Location

Pipestone Energy's land position is located just southwest of Grande Prairie, Alberta. Grande Prairie is a major services hub for the Canadian oil and natural gas industry, with depots and headquarters for drilling, completions and production service providers and oilfield equipment suppliers, as well as a large, qualified workforce. In addition to being located near major off-take facilities and strategic transportation infrastructure for both liquids and natural gas, Grande Prairie is also serviced by Canadian National Railway, which transports equipment and materials, such as facilities components, structural steel, line pipe, casing, tubing, cement, hydraulic fracturing chemicals and proppant.

Specialized Skill and Knowledge

Pipestone Energy employs a team with a range of professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to: geology, engineering, land, finance, accounting, legal, marketing, business development and information technology. Pipestone Energy also engages consultants to assist in areas in which it does not require full-time employees or areas that consultants are deemed to be more effective. Drawing on significant experience in the oil and natural gas business, Pipestone Energy believes its management team has a demonstrated track record of bringing together all of the key components of a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; a culture encouraging technical innovation and differentiation; and an entrepreneurial spirit that allows Pipestone Energy to effectively identify, evaluate and execute on value-added initiatives.

Competitive Conditions

The energy business is highly competitive. Pipestone Energy's competitors include both domestic and international majors, intermediates, and junior oil and natural gas companies. The Company competes for property acquisitions and the equipment and labour required to operate and develop its properties. The Company also competes for access to third-party gathering system infrastructure and processing facilities as well as market access in both the transportation and sale of its final products. The Company's competitors may be able to pay more for properties and may be able to define, evaluate, bid for and purchase a greater number of properties than Pipestone Energy. Ultimately, the Company's future success will depend upon its ability to develop or acquire additional reserves at costs that will allow it to remain competitive. See *"Risk Factors – The Company faces extensive competition in its industry"* and *"Risk Factors – The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies or qualified personnel may restrict the Company's operations"*. Pipestone Energy believes that it has a strong competitive position in the areas in which it operates.

Seasonality of Business

The volatility of commodity prices has a significant impact on the Company's financial performance. In general, natural gas, propane and to a lesser extent butane and condensate prices in Canada are seasonal in nature, with higher demand in the winter months (November to March) and lower demand in the summer months (April to October). Natural gas and liquefied petroleum gas prices are also impacted by the amount of gas in local and North America-wide storage, or inventory within the market. Pipestone Energy markets the majority of its gas production at AECO with the majority of prices reflecting daily variations (i.e. AECO 5A pricing). In 2022, approximately 20% of Pipestone Energy's natural gas production was sold in the United States and subject to Chicago Citygate pricing. To ensure that the capital program is adequately funded and to lessen the impact of seasonal cycles on cash flow, the Company utilizes financial instruments to fix an effective price for a portion of its sales volumes. See *"Statement of Reserves Data – Forward Contracts"*.

Pipestone Energy's operations are also impacted by seasonality, as road closures to heavy loads occur in the spring months, which can delay access or increase costs to access drilling locations. This has less of an impact on the Company's operations than some of its competitors due to the Company's all-season roads, pad drilling methods and use of specialized rigs. There are also periods of extreme cold weather that can potentially shut down or slow operations. Equipment becomes brittle in temperatures that can reach minus 58 degrees Fahrenheit (minus 50 degrees Celsius) with the wind chill factor, and staff movement in field areas can be hazardous under such conditions. See *"Risk Factors – The Company's activities are affected by seasonality"*.

ESG Practices

Pipestone Energy strives to be an industry leader with respect to ESG. The Company currently has a robust set of corporate policies in place, including a diversity policy, and has established committees, both at the board and management level, to steer its ESG initiatives. The Company believes that the socially responsible development of its core Montney asset is paramount to its long-term success. These values are embraced across the organization.

Pipestone Energy is committed to responsible development, and this commitment is demonstrated by its peer leading Scope 1 and Scope 2 emissions per boe, its commitment to improve and continue to lower its carbon footprint and GHG emissions as the Company pursues its net-zero emissions target by 2035.

Pipestone Energy released its second annual ESG report in September 2022 to demonstrate its achievements to date and continued commitment to ESG. This ESG report is available on the responsibility page of the Company's website at www.pipestonecorp.com.

In January 2022, the Company announced that it achieved independent certification of all its production from its Pipestone Montney asset under the Equitable Origin EO100™ Standard for Responsible Energy Development. The EO100™ standard represents leading industry practices for site-level ESG performance of energy and is based on a consensus from industry, NGOs, affected communities and government agencies to incentivize excellence in social and environmental performance of energy projects. Specifically, Equitable Origin has certified Pipestone Energy's produced natural gas against the five principles of the EO100™ Standard, including corporate governance and ethics; social impacts, human rights and community engagement; Indigenous Peoples' rights; occupational health & safety and fair labor standards; and environmental impacts, biodiversity and climate change. As part of certification, Pipestone Energy has committed to a continuous improvement plan encompassing all five principles.

Environmental, Health and Safety Policies

Pipestone Energy is committed to conducting its activities in a manner that protects the health and safety of its workers and the public while minimizing the Company's impact on the environment. Fostering a culture that prioritizes safety above all else is key to a sustainable future for our business. We thank the communities that Pipestone Energy works with and in and will continue our efforts to assist in building better communities. We strongly believe that our activities should impact our surrounding communities in a positive way.

Pipestone Energy endeavors to be in compliance with all health, safety and environmental requirements on an ongoing basis. The

Company has established guidelines and a management system to promote compliance with health, safety and environmental laws, including a robust Health and Safety program and detailed Emergency Response Plan. The Company also explores and implements various strategies to lower its carbon intensity and methane emissions and to forecast and manage risks associated with the potential impacts of climate change on the Company's operations.

The Company has designated personnel whose responsibility it is to monitor current and future regulatory requirements and their impact on the Company's business, as well as to implement appropriate compliance requirements. Pipestone Energy has also contracted the services of external consultants to provide it with expert advice on health, safety, environmental and regulatory compliance issues and to help it ensure that appropriate controls are implemented.

In addition, the Board of Directors has established the Reserves and Health, Safety & Environment Committee to oversee the Company's policies and management system and assess the Company's performance regarding the protection of the health and safety of all persons associated with the Company's operations, and the protection of the environment.

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which could have a significant negative impact on earnings and overall competitiveness of the Company. The Company is committed to meeting its responsibilities to protect the environment. For a description of the financial and operational effects of environmental protection requirements on the capital expenditures, earnings and competitive position of Pipestone Energy, see *"Risk Factors – The Company's operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to the Company's business activities"* and *"Risk Factors - The direct and indirect costs of various GHG regulations, existing and proposed, may adversely affect the Company's business, operations and financial results, including demand for the Company's products"*.

Employees

As at December 31, 2022, Pipestone Energy had 27 full-time employees in its Calgary office and 4 full-time employees at its Grande Prairie location, for a total of 31 full time employees. Pipestone Energy also had 4 consultants in its Calgary office and 25 consultants deployed in Grande Prairie field operations.

Industry Conditions

Companies carrying on business in the oil and natural gas sectors in Canada are subject to extensive controls and regulations which are imposed through legislation of the federal and respective provincial governments in the jurisdictions where a company may have assets or operations. While such regulations do not affect the Company's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such legislation, regulations and agreements carefully. The below outlines and summarizes certain conditions, regulations and events that impact the oil and natural gas industry, specifically in Alberta where the Company's assets are located.

Pricing and Marketing in Canada

Natural Gas

Negotiations 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/demand balance and other contractual terms of sale. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The pricing of condensate 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. The profitability of NGLs extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms of sale.

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinant of crude oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

In 2020, worldwide oversupply of crude oil, a lack of available storage capacity and decreased demand due to COVID-19 have had a continuing significant impact on the pricing of crude oil. In an effort to stabilize global oil markets, OPEC and a number of other oil producing countries announced an agreement to cut crude oil production by approximately 10 million bbls/d in April 2020, which was amended and adjusted throughout 2020 and early 2021. The oil markets began to rebalance in 2021 with oil prices reaching their highest levels in six years. The rebound continued into 2022 with a surge in oil prices in early 2022 primarily in response to the to the impact of the Russian invasion of Ukraine and OPEC+ decision to adhere to previously agreed upon production cuts, together with the improvement of global economic conditions and outlook due to reduced and eased COVID-19 restrictions. However, prices began to drop in the latter half of 2022. Amid fear of a global recession, increasing interest rates, lower demand and continuing sanctions and price caps placed on Russian oil, oil prices began to drop in the summer of 2022, with Saudi Arabia capping production and the G7 agreeing to put a price cap on Russian oil. At a meeting in early December 2022, OPEC+ decided to maintain its oil output targets following its decision in October 2022 to cut output by 2 million barrels per day. In December 2022, the ban placed on seaborne exports of Russian crude oil by the European Union came into effect, with the European Union also announcing a price cap which can be triggered starting February 15, 2023 if prices exceed 180 euros per megawatt hour for three days on the Dutch Title Transfer Facility gas hub's front-month contract. The G7 also announced a price cap of US\$60 on Russian oil in December 2022.

The continuing shift to alternative clean energy sources, there is added uncertainty around future oil demand growth, which is expected to continue into the future. While the trajectory of oil prices continue to be subject to uncertainty and volatility, factors such as the conflict in Ukraine continue to be unpredictable and may have an ongoing impact on oil demand and prices. See *"Risk Factors – Impact of the COVID-19 Pandemic and Risks Related Thereto"* and *"Risk Factors – Oil, condensate, other NGLs and natural gas prices are volatile. A sustained decline in oil, condensate, other NGLs and natural gas prices may adversely affect the Company's business, financial condition, results of operations and prospects."*

Exports from Canada

In connection with the implementation of a new impact assessment regime in Canada, the NEB was replaced with the CER in the summer of 2019. The CER, pursuant to the CERA and the IAA, regulates the export of oil, natural gas and NGLs from Canada.

Exports of oil, natural gas and NGLs 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 oil, natural gas and NGLs 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. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government.

Transportation Constraints and Market Access

Capacity to transport production from Western Canada to the United States and other international markets, has, and continues to be a major constraint on the exportation of crude oil, natural gas and NGL. Although certain pipeline and other transportation and export projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Due in part 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.

Pipelines

Producers negotiate with pipeline operators to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and the specific substance. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers and the price received.

Pursuant to 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 Cabinet approval before they can proceed. 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, public interest groups and 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 such 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 NGL, including pipelines, rail, trucks and marine transport. Improved access to global markets through the Midwest United States and export shipping terminals on the West coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

Natural Gas and LNG

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. Companies that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has been volatile (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to further reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NGTL to prioritize deliveries into storage (*temporary service protocol*). The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. An expansion to the NGTL system was recommended for approval by the CER which was sent to the federal Cabinet for approval. On April 30, 2021, the GIC approved the issuance of the certificate of public convenience by the CER.

The expansion to the NGTL system consists of approximately 344 km of 48-inch pipe and three compressor unit additions along NGTL's existing Grande Prairie mainline and Edson mainline in Alberta. Once complete and all of its facilities are placed into service, the expansion to the NGTL system will add 1.45 Bcf/d of capacity to the NGTL system. On August 11, 2022, TC Energy communicated its expectation that facilities providing up to 1.3 Bcf/d (approximately 90% of the total capacity) would be in-service in the fourth quarter of 2022 with 100% capacity expected to be in-service in the first quarter of 2023.

In July 2020, the Explorers and Producers Association of Canada applied to extend the temporary service protocol, which was opposed by NGTL and ultimately denied by the CER in February 2021.

In January 2022, the CER issued its decision denying NGTL's application for a proposed firm transportation linked service from receipt points along the North Montney Mainline in Northeast British Columbia to the proposed Willow Valley Interconnect delivery point. In its decision, the CER stated the tolling methodology proposed would result in unjust and unreasonable tolls.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, opposition from environmental and Indigenous groups and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the CGL Pipeline. Pre-construction activities began in November 2018, with a completion target of 2025.

In May 2020, TC Energy sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline has faced intense legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays to construction activities on the CGL Pipeline. The CGL Pipeline is currently approximately 80% complete and is expected to have a mechanical in-service date by the end of 2023 or early 2024.

International Trade Agreements

NAFTA/USMCA

NATFA, which previously existed among the governments of Canada, the United States and Mexico, has been replaced by a new trade agreement, widely referred to as the USMCA and sometimes referred to as the Canada United States Mexico Agreement. The USMCA came into force on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, the implementation of the USMCA could have an impact on Western Canada's petroleum and natural gas industry at large, including the Corporation's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach other international markets.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world and, as a result, a number of free trade or similar agreements are in force between Canada and certain other countries. Canada and the European Union recently agreed to the CETA, which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA has not received full ratification by national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of Brexit, the United Kingdom and Canada have reached an interim post-Brexit trade agreement, the CUKTCA. On December 9, 2020, the Government of Canada introduced Bill C-18, an *Act to Implement the Trade Continuity Agreement*. CETA ceased to apply to Canada-United Kingdom trade

on January 1, 2021 and CUKTCA came into force on April 1, 2021. The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

Canada and 10 other countries signed the CPTPP on March 8, 2018, which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among: Canada, Australia, Japan, Mexico, New Zealand, Singapore, Vietnam, and Peru. As other countries ratify the agreement, they are added to the annexes. The CPTPP facilitates temporary entry to Canada for certain categories of business persons who are citizens of other countries which are signatories to the CPTPP.

While it is uncertain what effect CETA, CPTPP, CUKTCA or any other trade agreements will have on the oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

Land Tenure

Mineral Rights

The respective provincial governments (i.e. the Crown) predominantly own the mineral rights to most of the crude oil and natural gas located in Western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. Crude oil and natural gas leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

In response to COVID-19, the governments of Alberta, British Columbia and Saskatchewan announced measures to extend or continue Crown leases and permits that may have otherwise expired in the months following the implementation of pandemic response measures. In March 2020, the British Columbia Ministry of Energy, Mines and Low Carbon Innovation announced that it was suspending posting requests and dispositions of petroleum and natural gas rights until further notice due to COVID-19. In December 2020, the monthly tenure process was resumed.

To develop crude oil and natural gas resources, it is necessary for the mineral rights owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage.

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences. British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by the federal government on behalf of First Nations or national parks and by private freehold owners. Rights to explore for and produce privately-owned crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop crude oil and natural gas reserves.

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, which is a federal government agency, manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, crude oil and natural gas activities conducted on Indian reserve lands were governed by the IOGA and the *Indian Oil and Gas Regulations, 1995* (the *1995 Regulations*). In 2009, Parliament passed the Modernized IOGA; however, the amendments were delayed until the federal government was able to complete stakeholder consultations and update the 2019 Regulations. The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019.

Surface Rights

To develop crude oil and natural gas resources, it is necessary for the mineral rights owner to have access to the surface lands as well. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage.

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the freehold mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production.

Producers and working interest owners of crude oil and natural gas rights may also create additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests, the terms of which are subject to negotiation.

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

In Alberta, provincially-set royalty rates apply to Crown-owned mineral rights and oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* (Alberta) was amended in 2014 to shorten the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three.

In 2016, the Government of Alberta adopted the Modernized Framework that applies to all conventional oil (i.e. not oil sands) and natural gas wells drilled after December 31, 2016 that produce Crown-owned resources. The Old Framework will continue to apply to wells producing Crown-owned resources that were drilled prior to January 1, 2017 until December 31, 2026. As of January 1, 2027, these older wells will become subject to the Modernized Framework. The *Royalty Guarantee Act* (Alberta), which came into effect on July 18, 2019, provides that no major changes will be made to the current crude oil and natural gas royalty structure for a period of at least 10 years.

Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis. The cost component is based on a Drilling and Completion Cost Allowance formula that relies, in part, on the industry's

average drilling and completion costs, determined annually by the AER, and incorporates information specific to each well such as vertical depth and lateral length.

In accordance with the Modernized Framework, producers initially pay a flat royalty rate of 5% of gross revenue from each producing well 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. Following payout, producers pay an increased post-payout royalty on revenues at a royalty rate between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all 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 and operates on a sliding scale. 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 toward a rate of 5% 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.

Subject to certain available incentives, royalty rates for conventional crude oil production subject to the Old Framework range from a base rate of 0% to a cap of 40%; royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 meters deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane.

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.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner.

Freehold Mineral Taxes are levied annually for production from freehold mineral lands. On average, the tax levied in Alberta is 4% 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.

Regulatory Authorities and Environmental Regulation

The Canadian oil and natural gas industry is subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to government review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and natural gas industry operations, such as Sulphur dioxide and nitrous oxide. The regulatory regime sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and GHG emissions (typically measured in terms of their global warming potential and expressed in terms of CO₂e), may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate

environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails.

On August 28, 2019, the IAA replaced the CEAA 2012 at the same time that the CERA replaced the NEB Act and the CER replaced the NEB. As part of the regulatory transition, the IA Agency replaced the Canadian Environmental Assessment Agency.

The enactment of the CERA and the IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. However, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer manage strategic, administrative and policy considerations while adjudicative functions fall to independent commissioners. Despite its structural change, the CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

The IAA is similar to the repealed CEAA 2012 in that it relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the IA Agency or, in the case of certain pipelines, a joint review panel comprised of members of the CER and the IA Agency. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights and peoples. It also requires an expanded public interest assessment, including Indigenous consultation, as applicable. The impact assessment must look at the direct result of the project's construction and operation. Designated projects specific to the oil and natural gas industry include pipelines that require more than 75 km of new right of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA. On May 10, 2022, the Alberta Court of Appeal released its opinion stating that the IAA went beyond the federal Parliament's constitutional authority and reached into areas of exclusive provincial authority. The federal government has appealed the Alberta Court of Appeal's opinion to the SCC. A date for arguments has not been scheduled, but filing deadlines have been set for early 2023.

On June 21, 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* received Royal Assent and immediately came into force. Bill C-15 is the Government of Canada's response to requests to implement the *United Nations Declaration on the Rights of Indigenous Peoples* as a framework for reconciliation in Canada.

Alberta

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* (Alberta) and a number of related statutes including the OGCA, the *Oil Sands Conservation Act*, the *Pipeline Act* and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources, including allocating and conserving water resources, managing public lands and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure.

The Government of Alberta relies on regional planning to accomplish its resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Protected Areas (previously known as the Ministry of Environment and Parks), the Alberta Ministry of Energy, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, increased seismicity induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate crude oil and natural gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all crude oil and natural gas producers working in certain areas where the likelihood of increased seismic activity is higher, and implemented the requirements in *Subsurface Order Nos. 2, 6 and 7*. Crude oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions, and trigger a sliding scale of obligations from the crude oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

Liability Management

The AER oversees liability management in the Province of Alberta. On June 30, 2020, the Government of Alberta announced the new AB LMF that will replace the AB LMR Program and its constituent programs. The goal of the AB LMF is to implement a holistic and full lifecycle approach to reclamation and remediation obligations. Since the announcement, the Government of Alberta has gradually begun to phase-in the AB LMF through legislative and AER directive amendments.

The announcement and implementation of the AB LMF and the desire to rethink liability management in Alberta follows the SCC's decision in *Orphan Well Association v Grant Thornton Ltd.* (also known as the *Redwater* decision). As a result of the Redwater decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licencees or to require a licencee to pay a security deposit before approving a transfer when such a licencee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta passed the LMSAA which came into force on proclamation. The LMSAA places the burden of a defunct licencees' abandonment and reclamation obligations first on the defunct licencee's working interest partners, and second, the AER may order the Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner.

Alberta's OGCA established an Orphan Fund which is run by the OWA to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licencee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund was originally conceived to be bankrolled exclusively by licencees in the former AB LLR Program and AB OWL Program who contributed to a levy administered by the AER. However, the Government of Alberta has loaned the Orphan Fund approximately \$335 million. The Government also covered \$113 million in levy payments that licencees 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. Collectively, these programs were designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licencees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. Under the new AB LMF, the OWA has broader authority to assist in the reclamation and remediation of wells, facilities or pipelines.

The AB LMR Program previously governed most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consisted of three distinct programs: the AB LLR Program, the AB OWL Program and/or the Large Facility Liability Management Program.

Following the Redwater decision, Alberta has committed to actively reducing inventories of orphan and inactive well sites in the province. It is the goal that the AB LMF will assist in addressing the OWA's inventory, creating a framework and regulatory scheme that will better manage site reclamation throughout the lifecycle of a project. The AB LMF addresses five key components supporting a lifecycle approach to liability management: (i) practical guidance and support for distressed operators; (ii) licensee capability assessment system to provide proactive support through ongoing financial capability review; (iii) mandatory spend targets to support inventory reduction; (iv) a process to address legacy and post-closure sites or sites that were remediated, reclaimed or abandoned prior to the AB LMF; and (v) the OWA taking on a more involved role in managing clean-up of oil and natural gas facilities and infrastructure.

On December 1, 2021, the Government of Alberta announced amendments to *Directive 006: Licensee Liability Rating (LLR) Program* and a new *Directive 080: Licensee Life-Cycle Management* and accompanying *Manual 023: Licensee Life-Cycle Management*. A new *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* was also introduced in April 2021 which introduced new criteria for the AER to consider whether an applicant, licensee or approval holder poses an "unreasonable risk". Among other changes under the AB LMF, the AB LLR Program and security deposit collection for license transfer have been replaced with the Licensee Capability Assessment System, pursuant to *Directive 088: Licensee Life-Cycle Management*, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LLR Program and will establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. Importantly, the AB LMF provides proactive support to distressed operators and requires companies operating in Alberta's oil and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets. Under the AB LMF each licensee is required to meet mandatory annual spend targets for well closures and abandonments. During the summer of 2022, the AER announced it would increase spend targets for liabilities in 2023 from \$422 million to \$700 million and released forecasted targets through 2027, each of which are expected to increase annually by 9%.

In 2015, the AER also implemented the IWCP to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013. The IWCP applied to all inactive wells that were noncompliant with Directive 013 as of April 1, 2015. The objective was to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee was required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The compliance deadline for the final year of the IWCP was extended from April 1, 2020 to September 1, 2020 and was concluded in March of 2021.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure, the AER announced a voluntary ABC program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through 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. The ABC, together with the inventory reduction program implemented under the AB LMF, which implements mandatory closure spend targets over a 5-year rolling period, will enable companies to work together to share the costs of cleaning up multiple sites in one area.

The AB LMF continues to be implemented by the AER with gradual and phasing changes to legislative, regulatory and AER directives required to effectively implement the AB LMF and properly phase-out the AB LMR Program as the AB LMR Program is

integrated in several directives and throughout governing legislation.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and natural gas industry in Canada. These impacts are uncertain and it is not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Company's business, financial condition, results of operations and prospects. An example of a change in policy that may impact the oil and natural gas industry is the International Maritime Organization's implementation of regulations that limit the sulphur content of marine fuel oil, reducing the permissible amount of Sulphur from 3.5% to 0.5%, effective January 1, 2020.

Federal

Canada has been a signatory to the UNFCCC since 1992. Since its inception, the UNFCCC has instigated numerous policy changes with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. On January 20, 2021, President Biden of the United States signed an executive order to rejoin the Paris Agreement. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In December 2019, the United Nations Annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference, which was scheduled to take place in November 2021 in Glasgow.

The result of The 2021 United Nations Climate Change Conference, more commonly referred to as COP26, was the Glasgow Climate Pact, negotiated through consensus of the representatives of the 197 attending parties. Owing to late interventions from India and China, that weakened a move to end coal power and fossil fuel subsidies, the conference ended with the adoption of a less stringent resolution than some anticipated. During the conference, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030, however, they have also indicated that they expect to implement policies to exceed this target. In connection with this target, the Government of Canada released the Pan-Canadian Framework. On December 11, 2020, the Government of Canada released its HEHE Plan which builds on the Pan-Canadian Framework and provides a road map forward to meet Canada's 2030 emissions reduction target. The HEHE Plan includes a \$3-billion investment over five years to a Net-Zero Accelerator Fund to invest in projects to decarbonize large emitters, scale-up clean technology and otherwise accelerate industry transformation across all sectors. In addition, the HEHE Plan proposes to invest an additional \$964 million over four years towards renewable energy and grid modernization projects and \$300 million over five years to advance the use of clean and reliable energy in rural, remote and Indigenous communities. The third component of the HEHE Plan pertains to zero emission vehicles. This includes investing an additional \$287 million to continue the federal government's Incentives for Zero-Emission Vehicles program until March 2022, \$150 million over three years towards charging and refueling stations across Canada, and \$1.5 billion towards a Low-Carbon and Zero-Emissions Fuels Fund to increase the production of low-carbon fuels.

Also of relevance to the oil and natural gas industry, in June 2022, the federal government introduced the SUPPR. The SUPPR prohibits, subject to certain exemptions, the manufacture, import and sale of six categories of single-use plastics. The prohibitions on manufacture and import for sale in Canada and sale and manufacture, import and sale for export come into force on a rolling basis between December 2022 and December 2025.

On November 19, 2020, the federal government announced Bill C-12. Canada joins over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. Bill C-12 received royal assent on June 29, 2021 and legally binds the federal government to a process to achieve net-zero emissions by 2050. The legislation, among other things, sets rolling five-

year emissions-reduction targets (starting in 2030) and requires emissions reduction plans to reach each target on a reporting basis and enshrines greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

On June 21, 2018, the federal government enacted the GGPPA, which came into force on January 1, 2019. This regime has two parts: an OBPS and a regulatory Fuel Charge imposing an initial price of \$20/tonne of CO₂e emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country. In accordance with the HEHE Plan, the price on carbon is set to increase annually at a rate of \$15/tonne of CO₂e per year commencing in 2023 through to 2030. In August 2021, the federal government established strengthened minimum national standards for 2023 to 2030, which includes the requirement that all jurisdictions establish systems that align with the federal carbon pricing trajectory and benchmark requirements to 2030. Once in place, the systems will remain until 2027.

Alberta, Saskatchewan, Ontario and Manitoba each challenged the constitutionality of the GGPPA. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments were appealed to the SCC and the hearing took place in September 2020. On March 25, 2021, the SCC released its decision in *Reference re Greenhouse Gas Pollution Pricing Act*, upholding the constitutionality of a federal law establishing minimum national standards for carbon pricing in Canada.

Manitoba also made an appeal to the Federal Court stating the federal government did not act properly in imposing a minimum price on carbon because Manitoba was planning to use its own lower price. In October of 2021, the Federal Court rejected Manitoba's argument stating the federal government's actions were consistent with the purpose of the GGPPA as was upheld by the SCC.

Following the SCC's decision upholding the constitutionality of the GGPPA, any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum national stringency standards. Currently the Fuel Charge applies in each of Ontario, Manitoba, Yukon, Alberta, Saskatchewan and Nunavut while the OBPS applies in Manitoba, Prince Edward Island, Yukon, Nunavut and partially in Saskatchewan. For so long as the provincial systems in Prince Edward Island, Alberta (under the TIER regulation) and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable.

On April 26, 2018, the federal government passed the Federal Methane Regulations. The Federal Methane Regulations seek to reduce emissions of methane from the petroleum and natural gas industry, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

As part of its efforts to provide relief to Canada's petroleum and natural gas industry in light of the COVID-19 pandemic, on October 29, 2020, the federal government launched the \$750-million Emission Reduction Fund to reduce methane and GHG emissions. The fund will provide repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies.

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

The federal government has enacted the *Multi-Sector Air Pollutants Regulation* under the authority of the *Canadian Environmental Protection Act, 1999*, which seeks to regulate certain industrial facilities and equipment types, including boilers and heaters used in the upstream petroleum and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

The federal government has also announced that it will proceed with the development and implementation of a CFS that will require producers, importers and distributors to reduce the emissions intensity of gaseous, liquid and solid fuels. On December 18, 2020, the federal government published proposed CFS regulations, which came into force on June 21, 2022. The CFS regulations take a performance-based approach to reducing greenhouse gas emissions. The CFS regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to reduce the carbon intensity of their liquid fossil fuels. Beginning in 2023, the carbon intensity reduction requirement will start at 3.5 g CO₂e/MJ, increasing by 1.5 gCO₂e/MJ each year and reaching 14 gCO₂e/MJ in 2030. The standard will apply to any company that domestically produces or imports at least 400 cubic metres of liquid fossil fuels for use in Canada. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability to meet requirements in a cost-effective way that works for their business. The proposed regulations offer compliance credits tracked via the Credit and Tracking System, and created a credit market to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

Alberta

On November 22, 2015, the Government of Alberta introduced a CLP. Under this strategy, the CLA came into force on January 1, 2017 and established a fuel charge that was compliant with federal requirements. In December 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed.

In June 2019, the Government of Alberta repealed the CLA and the Fuel Charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently \$50/tonne of CO₂e and will increase to \$65/tonne on April 1, 2023. In December 2019, the federal government approved Alberta's TIER regulation, which applies to large emitters and those who have opted-in. The TIER regulation came into effect on January 1, 2020 and replaced the previous *Carbon Competitiveness Incentives Regulation*.

The provisions of the TIER regulation required that an interim review of the regulation be completed by December 31, 2022 giving stakeholders an opportunity to provide input on improvements to the TIER system and to enable the regime to meet the updated federal benchmark criteria for the assessment of the carbon pricing systems for 2023 to 2030. Following the comment period, the *Technology Innovation and Emissions Amendment Regulation* was adopted with certain amendments to the TIER Regulation becoming effective January 1, 2023. These amendments include meeting the federal standards for Alberta's carbon pricing system, the creation of sequestration credits for carbon capture, utilization and storage ("CCUS") projects and amendments to the number of credits that can be used to meet emission targets. The TIER regulation is set to undergo another review by December 31, 2026.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO₂e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Under the amendments, a 2% annual tightening rate will apply to facility-specific and high performance benchmarks. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program in specified circumstances despite the fact that they do not meet the 100,000 tonne threshold. The amendments reduced the threshold for those to opt-in from 10,000 tonnes of CO₂e to 2,000 tonnes of CO₂e per year. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta. As discussed above, the TIER regulation will continue to apply in Alberta for as long as it meets the federal stringency standards and the federal backstop will apply to the emission sources not covered by the TIER program.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* on January 1, 2020 and the AER simultaneously released an updated

edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting*. The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal. In May 2020, the Government of Canada and the Government of Alberta announced a preliminary equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply once the agreement is effective.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed \$1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the CO₂ emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by approximately 2.76 million megatonnes per year.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act*, 2010. It deemed the pore space underlying all land in Alberta to be and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. In May 2021, the Government of Alberta announced a competitive bid process under which it would issue rights for carbon sequestration, focusing on the development of strategically placed carbon sequestration hubs, avoiding stand-alone injection operations. As of the fall of 2022, the Government of Alberta approved a total of 25 hub proposals through two competitive bid processes. The selected companies will begin exploring how to safely develop their carbon storage hubs. If a proponent can successfully demonstrate their project can provide permanent storage, companies will have the opportunity to apply for the right to inject captured carbon dioxide at such project. The Government of Alberta has also announced it will invest \$40 million in 11 CCUS hub projects through Emissions Reduction Alberta.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap. Hydrogen is positioned to play a significant role in the de-carbonization of the global economy and Alberta has significant opportunity to play a major role both nationally and internationally. The Hydrogen Roadmap is divided into two phases. The first phase focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization. The Alberta Utilities Commission also released its Hydrogen Inquiry Report in September 2022 which reviewed the viability and impacts of hydrogen blending into natural gas distribution systems in Alberta.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and natural gas industry. In addition, Canada is a signatory to the UNDRIP and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and natural gas industry in Western Canada. On November 28, 2019, the DRIPA became law in British Columbia. The Government of British Columbia recently released its interim approach in furtherance of its implementation of DRIPA which outlines a process for how new policy and legislation in the province are to be aligned with the UNDRIP. The action plan is the first of its kind to be enacted by any province and it is uncertain as to what potential consequences the implementation of the plan and its effects on future legislative drafting.

The UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and natural gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The Government of Canada has expressed that implementation of the UNDRIP Act has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward, but has confirmed that, subject to the forthcoming opinion from the SCC, the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP Act.

On June 29, 2021, the British Columbia Supreme Court issued the Blueberry Decision, in which it determined that the cumulative impacts of industrial development on the traditional territory of the BRFN in Northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. Going forward, the Blueberry Decision may have significant impacts on the regulation of industrial activities in Northeast British Columbia. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties.

On October 7, 2021, the Government of British Columbia and the BRFN reached an initial agreement in response to the Blueberry Decision in which the parties agreed to negotiate a land management process for BRFN territory, and certain previously authorized forestry and oil and gas projects were put on hold pending further negotiation. On January 18, 2023, the Government of British Columbia and the BRFN signed the Implementation Agreement. On January 20, 2023, the Government of British Columbia also finalized the Consensus Document with the Treaty 8 Nations. Both the Implementation Agreement and the Consensus Document respond to the Blueberry Decision. The precedent established by the Implementation Agreement and the Consensus Document may extend beyond Treaty 8 territory and may have implications for resource development in British Columbia, Alberta and Canada at large.

The key elements of the Implementation Agreement are:

- *Wildlife Management:* The Government of British Columbia and BRFN are committing to bring together Indigenous knowledge and western science. Both parties will support a community stewardship, monitoring and guardian program. Further, important species will be closely monitored.
- *Land-Use Plans:* The Government of British Columbia and BRFN will engage in collaborative land-use planning, to determine whether certain activities can occur in Treaty 8 territory. Collaborative land-use planning includes a commitment to advance watershed-level land use plans within the next three years (Watershed Management Basin Plans).
- *Petroleum and Natural Gas:* The Government of British Columbia and BRFN will use a more collaborative approach to oil and natural gas development planning and projects. The Government of British Columbia, various companies and other First Nations will sit together and address: the establishment of areas for permanent protection; minimizing disturbance from petroleum and natural gas development; reducing new disturbance from petroleum and natural gas by approximately 50 percent from pre-Blueberry Decision years; introducing operational and strategic planning expectations for the sector; and limiting overall new disturbances from petroleum and natural gas activities in BRFN's claim area.
- *Forestry:* The Government of British Columbia and BRFN will protect old growth forest and reduce timber harvesting in defined high value areas. Key elements of the Implementation Agreement applicable to forestry include: a cessation to aerial herbicide use; a commitment to implementing ecosystem-based management, through Watershed Management Basin Plans; and two-year harvest schedule outside the BRFN's important forestry areas.
- *Honoring Treaty 8:* The Government of British Columbia and BRFN have agreed to work together on measures to honor Treaty 8, including improving awareness and education on Treaty 8. The Government of British Columbia and BRFN will honor Treaty 8 by sustaining communications, sharing training and awareness building, and providing support for communications with other Treaty 8 First Nations and local elected elders.

The Implementation Agreement also includes a \$200 million restoration fund, which is meant to restore the land from industrial disturbance by June 2025. Further, BRFN will receive \$87.5 million as a financial package, with an opportunity for increased benefits based on petroleum and natural gas revenue-sharing and provincial royalty revenues in the next two years.

According to the Government of British Columbia, the Consensus Document will address the cumulative impacts of industrial development on the meaningful exercise of Treaty 8 rights in the territory, restore land and produce stability and predictability for industry in the region and to promote responsible resource development and sustainable economic growth in Treaty 8 territory. Further, it aims to manage the impacts of industrial development through ecosystem-based stewardship and

governance. The Consensus Document sets out various initiatives to outline how the Government of British Columbia and Treaty 8 Nations manage the land to achieve sustainability for future generations, meet the Crown's obligations to uphold constitutionally protected rights and support responsible resource development and economic activity in northeastern British Columbia. Specifically, the initiatives outlined in the Consensus Document include: (i) a new approach to wildlife co-management; (ii) new land-use plans and protection measures; (iii) a "cumulative effects" management system; (iv) pilot projects to advance shared decision-making for environmental planning and stewardship; (v) a multi-year, shared restoration fund; (vi) a new revenue-sharing approach to support the priorities of Treaty 8 First Nation communities; and (vii) actions to promote education about Treaty 8 through collaborative promotion, anti-racism training and awareness building.

The Government of British Columbia is still in ongoing discussions with other Treaty 8 First Nations, including McLeod Lake Indian Band, Prophet River First Nation and West Moberly First Nations.

The Implementation Agreement and Consensus Document remain confidential at the date of this AIF. Although the details have not been released, it is highly likely those documents will create additional consultation and regulatory obligations for operators seeking to develop natural resources in the affected region.

In July 2022, the Duncan's First Nation in Northern Alberta filed a lawsuit claiming cumulative effects from industry, agriculture and settlement which violate their treaty rights. The claim advances many of the same grounds as those that were the subject of the Blueberry Decision.

The long-term impacts and risks of the Blueberry Decision, and any subsequent decisions, on the Canadian oil and natural gas industry remain uncertain.

Accountability and Transparency

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

Risk Factors

The following is a list of risks that the Company faces in its normal course of business and summary of certain conditions, regulations and events that impact the crude oil and natural gas industry. The risks and uncertainties set out below are not the only ones the Company is facing. There are additional risks and uncertainties that the Company does not currently know about or that the Company currently considers immaterial which may also impair the Company's business operations and cause the price of the Common Shares to decline. If any of the following risks actually occur, the Company's business may be harmed and the Company's financial condition and results of operations may suffer significantly.

Risks Related to the Company

The acquisition, exploration and development of crude oil, condensate, other NGLs and natural gas properties and the production, transportation and marketing of crude oil, condensate, other NGLs and natural gas involves many risks, which may influence the ultimate success of the Company. While Pipestone Energy realizes these risks cannot be eliminated, it is committed to monitoring and mitigating these risks. These risks include, but are not limited to the following:

Oil, condensate, other NGLs and natural gas prices are volatile. A sustained decline in oil, condensate, other NGLs and natural gas prices may adversely affect the Company's business, financial condition, results of operations and prospects.

The Company's revenues, operating results, profitability, future rate of growth and the carrying value of the Company's oil and natural gas properties depend primarily upon the prevailing prices for oil, condensate, other NGLs and natural gas. Historically, oil, condensate, other NGLs and natural gas prices have been volatile, and they are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond the Company's control, including:

- worldwide and domestic supplies of oil, condensate, other NGLs and natural gas, including storage levels of these products;
- price levels, and expectations about future prices, of oil, condensate, other NGLs and natural gas and the differential between commodity prices in North America;
- the cost and risks of exploring for, developing, producing and delivering oil, condensate, other NGLs and natural gas;
- operational problems affecting pipelines, railway lines and processing and storage facilities;
- the expected rates of declining current production;
- weather conditions, including hurricanes, fires, flooding and other natural disasters that can affect oil, condensate, other NGLs and natural gas operations over a wide area;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the nature and extent of regulation relating to carbon dioxide and other GHG emissions;
- technical advances affecting energy consumption;
- risks associated with operating drilling rigs;
- the availability of pipeline capacity and other transportation facilities necessary to access local and international markets;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes and allowable production and exportation of oil and natural gas;
- the ability of the members of OPEC+ and their allies to agree to and maintain oil price and production controls;
- speculative trading in oil and natural gas derivative contracts;
- the nature and extent of environmental regulations, including those relating to abandonment and reclamation and remediation;
- political or economic instability or armed conflict in oil and natural gas producing regions, including Eastern Europe, the Middle East, Africa, South America and Russia;
- trade policies of the Government of Canada and foreign nations;
- the overall domestic and global economic environment;
- rate of acceleration and/or deceleration of the United States production growth;
- impact and duration of significant virus outbreaks or pandemics, including but not limited to COVID-19 and its variants, and the associated restrictions imposed by national, regional and local governments that could lower the demand for oil, condensate, other NGLs and natural gas; and
- the impact and duration of the conflict between Russia and Ukraine and any ramifications to the supply and demand for Russian produced oil, condensate and other NGLs and natural gas.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, condensate and other NGLs and natural gas price movements with any certainty. A material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil, condensate and other NGLs and natural gas and a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices.

Prices may continue to be volatile throughout 2023, which could have an impact on realized prices for Canadian producers. Oil, condensate and other NGLs prices may be unstable because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economy (including the continued impact of COVID-19 and its variants and the re-opening of China, and the ongoing conflict between Russia and Ukraine), OPEC+ actions, uncertainty relating to the pace of

production growth in the United States, sanctions imposed on certain oil producing nations by other countries, ongoing tensions in the Middle East, ongoing credit and liquidity concerns and the impact of protectionist measures on foreign trade. Oil, condensate and other NGLs and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil, condensate and other NGLs and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on development and exploitation projects.

Additionally, supply in excess of current pipeline and refining capacity in Canada is expected to continue to exist. Materialization of significant structural changes are required to reduce these bottlenecks and the resulting price discounts on Western Canadian products. The differential between commodity prices in the United States and Western Canada can be significant as a result of supply in excess of current pipeline and refining capacity at times. Various pipeline expansion projects to provide increased access to eastern Canadian refineries, the United States as well as new offshore markets, have been announced and are in various stages of review, approval and construction, but uncertainty as to the timing and completion of these projects persists.

All these factors could result in a material decrease in Pipestone Energy's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil, condensate and other NGLs and natural gas would have an adverse effect on the carrying value of the Company's reserves, borrowing capacity, revenues, profitability and funds from operations and may have a material adverse effect on its business, financial condition, results of operations and prospects.

Volatile crude oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for crude oil and natural gas producing properties, as buyers, sellers, lessors and lessees have difficulty agreeing on the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions or divestitures.

To attempt to reduce its price risk, the Company hedges a portion of its oil, condensate and natural gas production. The Company can provide no assurance that such transactions will reduce the risk or minimize the effect of any decline in oil and natural gas prices. See "*Industry Conditions – Pricing and Marketing in Canada*".

Declining general economic, business or industry conditions and inflation may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Concerns over global economic conditions, rising interest rates and fluctuations in foreign exchange rates, stock market volatility, energy costs, geopolitical issues, OPEC+ actions, rising inflation, the availability and cost of credit, the volatility of major stock exchanges, the uncertainty surrounding the re-opening post COVID in the People's Republic of China and trade disputes between the United States and the People's Republic of China, the continued spread of COVID-19 and its variants, have all contributed to increased economic uncertainty, predictions of recession in various parts of the world and in general diminished expectations for the global economy. Concerns about global economic growth have had a significant adverse impact on global financial markets and caused volatility in commodity prices. If the economic climate in Canada, the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which the Company can sell its oil, condensate, other NGLs and natural gas, affect the ability of the Company's vendors, suppliers and customers to continue operations and ultimately adversely impact the Company's results of operations, liquidity and financial condition.

The Company's actual capital costs, operating costs and economic returns may differ significantly from those it has anticipated.

The Company's actual capital costs, operating costs and economic returns particularly in light of inflationary pressures, may differ significantly from the estimates contained in the McDaniel Reserves Report and other studies or estimates prepared by or for the Company. For example, the Company may not succeed at maintaining its well costs in the future, transportation for the Company's production may not be secured or may not be secured at a reasonable cost, the Company's capital costs to further develop the Pipestone Project may be significantly higher than anticipated or the ultimate returns from the Pipestone Project may be significantly lower than expected. The Company uses scientific methods and analog reservoirs to estimate ultimate recovery. These estimates may not prove to be correct. There is therefore a risk that the Pipestone Project will not support the

expected number of wells or that the wells will not recover as much hydrocarbons as projected. There can be no assurance that the Company's actual operating costs will not be higher than currently anticipated. If the Company's actual costs are higher than its current estimates this may adversely affect the Company's financial position, results of operations and cash flows.

The Company's success depends on finding, developing or acquiring additional reserves, which requires significant capital investment. The Company may not be able to obtain needed capital or financing on satisfactory terms or at all.

The Company's future success depends upon its ability to find, develop or acquire additional oil, condensate, other NGLs and natural gas reserves that are economically recoverable. The Company's reserves and production therefrom will generally decline as reserves are depleted, except to the extent that the Company conducts successful exploration or development activities or acquires additional properties containing reserves, or both. To increase reserves and production, the Company undertakes development, exploration and other replacement activities or uses third parties to accomplish these activities. The Company has made and expects to make in the future substantial capital investments in its business and operations for the development, production, exploration and acquisition of oil, condensate, other NGLs and natural gas reserves. Historically, the Company has financed capital investments primarily with the issuance of equity and borrowings under its bank and other credit facilities. The Company intends to finance its future capital investments primarily through reinvestment of cash flow from operations and, only if necessary, through additional borrowings under its current RBL and by accessing capital markets; however, these sources may not be sufficient to fund the Company's ongoing activities at all times depending on prevailing market conditions.

The Company's cash flow from operations and access to capital are subject to a number of variables, including:

- its reserves;
- the level of oil, condensate and other NGLs and natural gas it is able to produce from existing wells;
- the prices at which oil, condensate and other NGLs and natural gas are sold; and
- its ability to acquire, locate and produce new reserves.

The Company may not have sufficient resources to undertake its exploration, development and production activities or the acquisition of oil, condensate and other NGLs and natural gas reserves, the Company's exploratory projects or other replacement activities may not result in significant additional reserves and the Company may not have success drilling productive wells at low finding and development costs. If the Company is unable to find, develop or acquire additional oil, condensate and other NGLs and natural gas reserves, its cash flow and results of operations may be adversely affected. As such, the Company may require additional financing in order to carry out its oil, condensate and other NGLs and natural gas acquisition, exploration and development activities that cannot be satisfied from cash flow from operations. There is a risk that if the economy and banking industry experiences unexpected and/or prolonged deterioration, the Company's access to additional financing may be affected. Because of global economic volatility, the Company may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such additional financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil, condensate and other NGLs and natural gas prices, operating difficulties, declines in reserves or otherwise, it will affect the Company's ability to obtain the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable, or available only on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result. Additionally, there can be no assurance that additional debt or equity financing will be available to meet these requirements on favourable terms or at all and equity financing may result in a change of control of the Company.

Negative public perception of oil sands development, oil and natural gas development and transportation, hydraulic fracturing and fossil fuels, may harm the Company's profitability and corporate reputation.

Development of the Alberta oil sands, oil, condensate and other NGLs and natural gas development and transportation, hydraulic fracturing and fossil fuels have figured prominently in recent political, media and activist commentary on the subjects of climate change, GHG emissions, water and other oil and gas usage, the environmental impacts of oil and gas development and the

transition from fossil fuels to alternative energy sources. Concerns over heightened GHG emissions and water and land use practices in oil sands developments may directly or indirectly reduce the profitability of the Company's current projects and/or the viability of all future projects in the Alberta oil sands and reduce the demand and pricing of the Company's condensate. The Company's corporate reputation may be negatively affected by the negative public perception and public protests against oil, condensate and other NGLs and natural gas development, transportation and hydraulic fracturing.

The Company's business may be materially adversely affected by recent political and social events and decisions made in the United States, Europe and elsewhere.

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the TPP and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The U.S. has not indicated any intention to rejoin the TPP but could try to negotiate stronger labour and environmental standards. On January 20, 2021, Mr. Joseph Biden was sworn in as the 46th President of the United States. The political unrest associated with the transition to the new Biden administration was unprecedented in the United States, and the short and long-term impacts on business and capital markets are unknown. Additionally, on January 20, 2021, the Biden administration announced its decision to revoke the federal permit granted by the former administration for the Keystone XL Pipeline, which has overturned a comprehensive regulatory process that lasted more than a decade. In addition, NAFTA has been replaced with the USMCA. This has affected the competitiveness of other jurisdictions, including Canada. On January 25, 2021, the Biden administration signed an executive order with respect to stringent new Made-In-America rules for the U.S. government and has indicated that the exceptions to such rules will be very limited. It is unclear what the impact of the new executive order will be and how it may impact the USMCA and the Canada-U.S. supply chain. Further, it is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the petroleum and natural gas industry. Any actions taken by the current United States administration may have a negative impact on the Canadian economy and on the businesses, financial condition, results of operations, prospects and the valuation of Canadian crude oil and natural gas companies, which could also negatively impact the Corporation, which negative impact could prove to be material over time.

In addition to the political disruption in the United States, the impact of Brexit remains to be determined, especially in a post-pandemic era. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, costs for goods and services required for the Company's business could increase and access to skilled labour could decrease, negatively impacting the Company's business, financial condition, results of operations, prospects and the market value of its Common Shares, which negative impact could prove to be material over time.

Beginning in November 2021, Russia began to amass troops along the Ukrainian border, heightening military tension in Eastern Europe. In February 2022, Russia sent troops into pro-Russian separatist regions in Ukraine. Ongoing military tensions between Russia and Ukraine have the potential to threaten supply of oil and gas from the region and impact demand from other European countries as well as the possibility that other nations will impose certain tariffs and restrictions on oil from Russia. The long-term impacts of the tension between Russia and the Ukraine remains unclear, including the responses from other nations globally.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the petroleum and natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project. In January 2020, the SCC unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, tensions remain between provincial and federal governments. Continued uncertainty and delays, including a temporary shutdown due to flooding in British Columbia have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdictions where the Corporation's operations are located.

Following former Alberta Premier Jason Kenney's resignation on May 18, 2022, Danielle Smith was elected as Premier on October 11, 2022. Shortly after her appointment, Premier Smith introduced the Sovereignty Act. The Sovereignty Act was passed on December 8, 2022 and received Royal Assent on December 15, 2022. The Sovereignty Act, amongst other things, enables the Alberta Government to choose which federal legislation, policies or programs it will enforce in Alberta, providing an overriding right to not enforce those which the Alberta Government deems to be "harmful" to Alberta's interests or infringe on the Federal Constitution and its division of powers. The Sovereignty Act has been opposed by many, including the National Democratic Party and various Indigenous groups who have expressed concern as to how the Sovereignty Act will affect Indigenous rights and consultation obligations in Alberta. It is unclear what the effect the Sovereignty Act will have on Alberta, including the petroleum and natural gas industry, Alberta businesses and its federal and interprovincial relationships, including the application of certain federal legislation in Alberta, such as the GGPPA and the IAA and the way in which the Alberta Government may address any legislative and policy gaps created. Although the Sovereignty Act has not yet been challenged in court, it is possible the Sovereignty Act's constitutionality will be challenged.

The federal government was re-elected in 2019, but in a minority position. Another federal election was held on September 20, 2021 and the federal government was re-elected again in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the petroleum and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial government level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the petroleum and natural gas industry, which effect could prove to be material over time. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access – Specific Pipeline and Proposed LNG Export Terminal Updates*", and "*Industry Conditions – International Trade Agreements*".

Inflation and Cost Management.

The Company's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. The Company's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on the Company's financial performance and funds from operations.

The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to the Company's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and funds from operations.

The Company may encounter challenges in accessing insurance for its operations and, if available, it may only be offered at higher costs as major insurers begin to implement their ESG policies, goals and targets.

In 2020 a major global insurer, as part of its ESG sustainability plan, announced that it would be withdrawing new insurance coverage and existing coverage over the next decade from companies with a significant portion of their revenue derived from thermal coal-fired power plants, thermal coal mines, oil sands or arctic energy exploration activities. Although this announcement does not directly target the Company's business, as this trend towards clean-energy and reduction of fossil fuel reliance continues this could result in other insurers following similar practices and or limiting available re-insurance providers. This could result in the Company being adversely affected when trying to access insurance coverage in the future if it is unable to adhere to the ESG guidelines implemented by its insurers for their clients.

The Company's access to capital may become constrained as large sovereign wealth funds and other large institutional investors move towards net zero carbon investment strategies.

Some of the world's largest investors managing significant asset bases have committed to investing only in companies with pledges to achieve net zero carbon dioxide emission targets, with a common timeframe to achieving net zero being set by the year 2050. The Company may have challenges accessing additional capital in the future if it is unable to set and achieve net zero carbon dioxide emission or other environmental targets expected by the broader investment community. While Pipestone Energy strives to be a leader amongst its peer group with respect to ESG initiatives, certain carbon dioxide emission and other environmental targets could be unattainable due to the nature of the Company's operations.

Federal and provincial legislative and regulatory initiatives regarding oil and natural gas development and fossil fuel activity could result in increased costs and additional operating restrictions or delays.

Any new laws, regulations or permitting requirements regarding oil and natural gas development or fossil fuel activity, including the implementation of the federal *Impact Assessment Act*, could lead to operational delays, increased operating costs or third-party or governmental claims, and could also increase the Company's compliance costs, delay the development of the Company's oil, condensate and other NGLs and natural gas resources and reduce the price the Company is able to realize from its production of oil, condensate and other NGLs and natural gas. Restrictions on oil sands development and fossil fuel activity could also reduce the amount of oil, condensate and other NGLs and natural gas that the Company is ultimately able to produce from its reserves. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

Federal and provincial legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is the process of pumping a fluid under pressure down a well, which causes the surrounding rock to crack or fracture. The fluid, typically consisting of water, sand, chemicals and other additives, flows into the cracks where the sand remains to keep the cracks open and allow natural gas or liquids to be recovered. Fracturing fluids are produced back to the surface through the wellbore and are stored for reuse or future disposal in accordance with applicable regulations, which may include injection into underground wells.

Water is an essential component of the Company's drilling and hydraulic fracturing processes. Limitations or restrictions on the Company's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions can result in local water authorities to take steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If the Company is unable to obtain water to use in its operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs which could have a material adverse effect on its financial condition, results of operations and cash flows.

Additionally, the Company must dispose of the fluids produced from crude oil, NGLs and natural gas production operations, including produced water, which it does directly or through the use of third-party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities.

Some provinces require the details of fracturing fluids to be submitted to regulators. In Alberta, the Alberta Energy Regulator has implemented restrictions and operating procedures regarding hydraulic fracturing through *Directive 083: Hydraulic Fracturing – Subsurface Integrity*. In order to carry out hydraulic fracturing operations a licensee must observe the prescribed setbacks for water wells and top of bedrock, conduct a risk assessment, and fulfill the reporting requirements set out in *Directive 059: Well Drilling and Completion Data Filing Requirements* which include reporting water source and fracture fluid data. These and other applicable regulations could increase the cost of the Company's operations.

While hydraulic fracturing has been in use and improved upon for many years, there has been increased focus on environmental aspects of hydraulic fracturing practices in recent years.

Due to seismic activity reported in Alberta which is suspected to be caused by hydraulic fracturing activity, the AER has implemented seismic monitoring and reporting requirements for hydraulic fracturing operators. These requirements include, among others, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events, and the suspension of operations if a seismic event above a particular threshold occurs. The AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if deemed to be necessary.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, condensate and other NGLs and natural gas, including from the development of shale and other "tight" resource plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, provincial or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and natural gas wells, increased compliance costs and time, which could adversely affect the Company's financial position, results of operations and cash flows.

The Company relies on surface and groundwater licenses, which if rescinded or the conditions of which are amended, could disrupt its business and have a material adverse effect on its business, financial condition, results of operations and prospects.

The Company relies on access to both surface and groundwater, which is obtained under government licenses, to provide the substantial quantities of water required for certain of its operations. There can be no assurance that the licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. Further, there can be no assurance that the Company will not have to pay increased fees for the use of water in the future or that any such fees will be reasonable. Finally, new projects or the expansion of existing projects may be dependent on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to the Company, or at all, or that such additional water will in fact be available to divert under such licenses. Any prolonged droughts in the Grande Prairie area could result in the Company's surface and groundwater licenses being subject to additional conditions or rescission. The Company's inability to secure surface and groundwater licenses in the future and any amendment to, or rescission of, its current licenses may disrupt its business and have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The Company may be unable to effectively manage growth.

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

The Company's failure to successfully identify and make attractive acquisitions, joint ventures or investments, or successfully integrate future acquisitions of properties or businesses could disrupt its business, reduce its earnings and slow its growth.

The Company may not be able to identify and complete acquisitions, joint ventures or investments on commercially attractive terms, or at all. The Company's ability to complete acquisitions is dependent upon, among other things, its ability to obtain debt and equity financing and, in some cases, regulatory approvals. Even if such acquisitions, joint ventures or investments are consummated, the Company may not be able to successfully integrate them. These acquisitions may be in geographic regions in which the Company does not currently operate, which could result in unforeseen operating difficulties and difficulties in coordinating geographically dispersed operations, personnel and facilities. In addition, if the Company enters into new geographic markets, it may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on the Company and its management, cause the Company to expend additional time and resources and increase the Company's exposure to penalties or fines for non-compliance with such additional legal requirements. Completed acquisitions could require the Company to invest further in operational, financial and

management information systems and to attract, retain, motivate and effectively manage additional employees. Furthermore, acquisitions of oil and natural gas properties or companies are based in large part on engineering, environmental and economic assessments. These assessments include a number of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and natural gas, future operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geological, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated and the Company may fail to realize the full benefit that it expects in estimated proved reserves, production, cost savings from operating synergies or other benefits anticipated from an acquisition. The inability to effectively manage the integration of acquisitions could reduce management's focus on its ongoing development and current operations, which, in turn, could negatively impact the Company's earnings and growth. Future acquisitions, joint ventures and investments could result in the incurrence of additional debt, contingent liabilities and amortization expenses related to goodwill and other intangible assets and increased depletion, interest, impairment of goodwill and other costs, any of which could have a material adverse effect on the Company's financial condition and operating results by reducing the Company's net profit or increasing the Company's total liabilities, or both. Any of these factors could adversely affect the Company's business, financial condition, results of operations or prospects.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies or qualified personnel may restrict the Company's operations.

The oil and natural gas industry is cyclical and equipment, materials and qualified personnel are mobile, which can result in shortages of drilling rigs, equipment, steel pipe, raw materials (particularly sand and other proppants), supplies and qualified personnel or the shortage of rail capacity to deliver equipment and raw materials. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and the demand for, and wage rates of, qualified drilling rig crews also rise with increases in demand. Rising costs due to inflation has occurred over the last two years and is expected to continue for the foreseeable future. In accordance with customary industry practice, the Company relies on independent third-party service providers to provide most of the services necessary to drill and complete new wells. If the Company is unable to secure a sufficient number of drilling rigs and completions spreads at reasonable cost, its financial condition and results of operations could suffer, and the Company may not be able to drill and complete wells across all of its acreage before its agreements expire. Shortages of drilling rigs, equipment, rail capacity, raw materials, supplies, personnel, trucking services, tubulars, hydraulic fracturing and completion services and production equipment could delay or restrict the Company's exploration and development operations, which in turn could impair the Company's business, financial condition, results of operations and prospects.

The direct and indirect costs of various GHG regulations, existing and proposed, may adversely affect the Company's business, operations and financial results, including demand for the Company's products.

The Company's exploration and production facilities and other operations and activities emit GHGs which may require the Company to comply with federal and/or provincial greenhouse gas emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require the Company to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chain, transport needs, and employee safety, which may in turn have a negative effect on the Company's production, which negative effect could prove material over time.

Foreign and domestic governments continue to evaluate and implement policy, legislation and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing operating expenses with respect to the Company's operations, and, in the long-term, potentially reducing the demand for crude oil and natural gas and related products, resulting in a decrease in the Company's profitability and a reduction in the value of its assets.

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels which influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and crude oil and natural gas companies responsible for climate change through climate litigation.

With respect to ESG and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the CSA published for comment proposed National Instrument 51-107 – *Disclosure of Climate-related Matters*, intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If the Corporation is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, its business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

Given the perceived elevated long-term risks associated with regulatory changes or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing, and providing insurance coverage to crude oil and natural gas and related infrastructure businesses and projects. The impact of such efforts may require the Company's management to dedicate significant time and resources to these climate change related concerns, may adversely affect the Company's operations, the demand for and price of the Company's securities and may negatively impact the Company's cost of capital and access to the capital markets, which negative impact could prove to be material over time.

Claims have been made against certain energy companies alleging that GHG emissions from crude oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities or other organizations may make claims against crude oil and natural gas companies, for alleged personal injury, property damage, or other potential liabilities. While the Company is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by the Company, impact its operations and have an adverse effect on its financial condition, which could prove to be material.

Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses and in the long-term, potentially reducing the demand for crude oil and natural gas production resulting in a decrease in the Company's profitability and a reduction in the value of its assets or requiring impairments for financial statement purposes.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns

pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns.

In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require the Company to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chain, transport needs, and employee safety. Specifically, in the event of water shortages or sourcing issues, the Company may not be able to, or will incur greater costs to, carry out hydraulic fracturing operations.

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of hydrocarbons which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation.

Although it is not possible at this time to predict how new laws or regulations in the U.S. and Canada would impact the Company's business, any such future laws, regulations or legal requirements imposing reporting or permitting obligations on, or limiting emissions of GHGs from, the Company's equipment and operations could require the Company to incur costs to reduce emissions of GHGs associated with its operations or to purchase emission credits or offsets as well as delays or restrictions in its ability to permit GHG emissions from new or modified sources.

The direct or indirect costs of compliance with these regulations may have a material adverse effect on the business, financial condition, results of operations and prospects of the Company. Any such regulations could also increase the cost of consumption, and thereby reduce demand for the oil, condensate and other NGLs and natural gas the Company produces. Given the evolving nature of the discourse related to climate change and the control of GHGs and resulting regulatory requirements, it is not possible to predict with certainty the impact on the Company and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

The Company may be unable to satisfy its obligations under its firm commitment transportation and processing arrangements.

Significant continued investment is required in order to maintain or increase the Company's production and offset production declines. If the Company does not sustain production levels sufficient to utilize its contracted firm transportation and processing capacity, the Company will be required to satisfy significant financial obligations under such firm commitment arrangements and incur the notional cost of transporting and processing volumes in excess of its production, which would have an adverse effect on the Company's financial condition.

The Company relies on a few key employees whose absence or loss could disrupt its operations and have a material adverse effect on its business.

The Company's success depends in large measure on certain key personnel and the recruitment and retention of a skilled workforce. Many key responsibilities within the Company's business have been assigned to a small number of employees. The loss of their services could disrupt the Company's operations and have a detrimental effect on the Company. Most of the Company's executives are not restricted from competing with the Company if they cease to be employed by the Company. In addition, the Company does not maintain "key person" life insurance policies on any of its employees. As a result, the Company is not insured against any losses resulting from the death of its key employees. The competition for qualified personnel in the oil and natural gas industry is intense and 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 its business. If the Company is unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, the Company could be negatively impacted, which negative impact could prove to be material over time. In addition, the Company could experience increased costs to retain and recruit these professionals.

The marketability of the Company's production is dependent upon compressors, gathering lines, pipelines, gas processing facilities and other facilities, certain of which the Company does not own nor control and which may fail or

not perform as predicted. When these facilities are unavailable, the Company's operations can be interrupted and its revenues reduced.

The marketability of the Company's oil, condensate and other NGLs and natural gas production depends in part upon the availability, proximity and capacity of processing facilities which are owned by third parties, including the Keyera Wapiti Gas Plant system, the Tidewater Pipestone Gas Plant system, the Veresen Hythe Gas Plant system or the CNRL Gold Creek Plant, as well as various other oil, condensate and other NGLs and natural gas pipelines, trucking and rail systems. In general, the Company does not own nor control the processing and transportation facilities that are used to process and transport the Company's production, and access to such facilities may be limited or denied with limited recourse to the Company. Such facilities may also fail or may not perform as predicted. A significant disruption in the availability of these processing and transportation facilities, rail systems and other production facilities could adversely impact the Company's ability to deliver to market or produce its oil, condensate and other NGLs and natural gas and thereby result in the Company's inability to realize the full economic potential of its production. If, in the future, the Company is unable, for any sustained period, encounters compression, processing or other production related difficulties, or is unable, for any sustained period, to implement acceptable delivery or transportation arrangements, the Company will be required to shut-in or curtail production from the field. Any such shut in or curtailment, or an inability to obtain favourable terms for delivery of the oil, condensate and other NGLs and natural gas produced from the field, would adversely affect the Company's financial condition and results of operations.

If any third-party gathering, compression, and processing systems such as the Keyera Wapiti Gas Plant system, the Tidewater Pipestone Gas Plant system, the Veresen Hythe Gas Plant system or the CNRL Gold Creek Plant become partially or fully unavailable to process the Company's production, or if quality specifications or physical requirements such as compression are altered by such third parties so as to restrict the Company's ability to transport its production on those pipelines or facilities, the Company's revenues could be adversely affected. If any of the third-party transportation facilities such as the TCPL, NGTL, Alliance Pipeline, Pembina Pipeline and other facilities and service providers upon which the Company depends to move production to market, become partially or fully unavailable to transport or process the Company's production, or if quality specifications or physical requirements such as compression are altered by such third parties so as to restrict the Company's ability to transport its production on those pipelines or facilities, the Company's revenues could be adversely affected. Restrictions on the Company's ability to move its oil, condensate and other NGLs and natural gas to market may have several other adverse effects, including fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event the Company is unable to market and sustain production under a particular petroleum and natural gas agreement for an extended period of time, possible loss of its rights under that agreement due to a lack of production. Upon the expiry of the Company's transportation arrangements, including with TC Energy, NOVA, Alliance and Pembina, the Company may be unable to extend the term of such arrangements on favourable terms, or at all, which could impact the Company's ability to move production to market and reduce the Company's revenues. The Company has historically carried contingent business interruption insurance on its operations to try and mitigate part of the potential negative financial impact that could result from unplanned and extended third-party downtime. There is no guarantee however that claims made under this insurance will be successful and benefit the Company or, if they are accepted by the insurers, that they will be paid out in a timely manner. The contingent business interruption insurance contains a minimum deductibility or waiting period of approximately one month and as such does not protect the Company from any short-term losses.

The Company's identified drilling locations, which are part of the Company's anticipated future drilling plans, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Pipestone Energy's identified prospective future drilling locations are expected to contribute to the Company's future production. The Company's ability to drill and develop these locations depends on a number of uncertainties, including, but not limited to, the availability of capital, equipment and personnel; oil, condensate and other NGLs and natural gas; inclement weather; capital and operating costs; drilling results and production rate recovery; gathering system and transportation constraints; the net price received for commodities produced; and regulatory changes. As a result of these uncertainties, there can be no assurance that the numerous potential drilling locations the Company has identified will ever be drilled or that the Company will be able to produce oil, condensate and other NGLs and natural gas from these or any other potential drilling locations. As such, the Company's actual drilling activities may materially differ from those presently identified, which could adversely affect the Company's business.

Drilling for oil, condensate and other NGLs and natural gas, successfully stimulating well productivity and producing oil, condensate and other NGLs and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment and adversely affect the Company's business, financial condition, results of operations and prospects.

The Company's future financial condition and results of operations will depend on the success of its exploration, development and production activities. The Company's drilling and well stimulation activities are subject to many risks. For example, the Company can provide no assurance that new wells drilled and completed by it will be productive or that the Company will recover all or any portion of its investment in such wells. Drilling for oil, condensate and other NGLs and natural gas and attempts to stimulate well productivity often involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil, condensate and other NGLs and natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The Company's hydraulic fracturing activities to complete new wells can affect the production from adjacent wells. The seismic data and other technologies the Company uses do not allow it to know conclusively prior to drilling a well that oil, condensate and other NGLs and natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond the Company's control, and increases in those costs can adversely affect the economics of a project. Further, the Company's drilling, hydraulic fracturing and producing operations may be curtailed, delayed, cancelled or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations;
- poor well performance or higher than anticipated rates of production decline;
- loss of drilling fluid circulation;
- loss of title or other title related issues;
- facility or equipment malfunctions;
- surface access restrictions;
- restrictions in oil, condensate and other NGLs and natural gas prices;
- limitations in the market for oil, condensate and other NGLs and natural gas;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- the effects of and response to COVID-19 and its variants;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

These risks can cause performance issues, substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties. In addition, drilling for unconventional oil, condensate and other NGLs and natural gas, stimulating well productivity and production of unconventional oil, condensate and other NGLs and natural gas resources pose additional operating risks different from conventional oil, condensate and other NGLs and natural gas production operating risks, including:

- higher capital costs than similar depth Conventional Natural Gas wells because of necessary alternative drilling or completion techniques, water production, treatment, transportation and disposal costs, additional compression, and other factors;
- relatively long pilot production test times to determine commerciality or optimal practices, as compared to conventional oil and natural gas fields;
- peak production rates, time to reach peak rate, and time that peak rate can be sustained, are subject to substantially greater uncertainty for unconventional oil and natural gas wells than conventional oil and natural gas wells;
- difficulties associated with producing water, including scale formation, paraffin, corrosion or back- pressure caused by inefficient pumping, restrictions on surface facilities capacity, failure of water disposal wells to adequately handle required volumes of produced water and related dewatering;
- difficulties associated with extreme weather conditions including potential freezing;
- more wells per section in some instances to optimally and cost-effectively develop reserves;

- reduced wellhead pressures needed for production, leading to larger flow lines or additional compression; and
- complexity of development of multiple productive zones.

Operating hazards and uninsured risks may result in substantial losses and could prevent the Company from realizing profits.

The Company's operations are subject to all of the hazards and operating risks associated with drilling for, production and transportation of oil, condensate and other NGLs and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, facility, pipe or pipeline corrosion, damage or failures, abnormally pressured formations, natural disasters, casing collapses and environmental hazards such as oil spills, produced water spills, gas leaks, ruptures, discharges of toxic gases including H₂S gas, or accidents while the Company's products are being transported by pipeline or trucked or shipped by rail. The Company's operations may also subject it to the risk of vandalism or terrorist threats, including eco-terrorism and cyber-attacks.

In addition, the Company's operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The occurrence of any of these events could result in substantial losses to the Company due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of operations, repairs to resume operations and adverse reputational consequences or loss of goodwill.

The Company has historically maintained insurance against some, but not all, of its business risks. The Company's insurance may not be adequate to cover any losses or liabilities it may suffer. Also, insurance may no longer be available to the Company or, if it is, its availability may be at premium levels, or subject to deductibles and other conditions that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by the Company or a claim at a time when the Company is not able to obtain liability insurance could have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause the Company to restrict its operations, which might severely impact its financial position. The Company may also be liable for environmental damage caused by previous owners of properties purchased by the Company, which liabilities may not be covered by insurance.

Since drilling and hydraulic fracturing activities are part of the Company's operations, they are covered by the Company's insurance against claims made for bodily injury, property damage and clean-up costs stemming from a sudden and accidental pollution event. However, the Company may not have coverage if it is unaware of the pollution event and unable to report the "occurrence" to its insurance company within the period required under the Company's insurance policy. The Company has no coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and the Company can provide no assurance that the insurance coverage will be adequate to cover claims that may arise, or that it will be able to maintain adequate insurance at rates it considers reasonable. There is also no assurance that a claim will be paid in a timely manner. The occurrence of an event not fully covered by insurance could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The Company's drilling activities will encounter Sour Gas.

To date all of the Company's wells have produced Sour Gas. A significant portion of the natural gas produced in Alberta originates as Sour Gas. Sour Gas requires specialized infrastructure in order to safely transport production from Pipestone Energy's field to third-party processing facilities (i.e. Keyera, Tidewater, Veresen and CNRL). The Company also believes it has other undeveloped lands that contain high enough concentrations of Sour Gas to require centralized Sour Gas processing facilities and that requirement is envisioned in the Company's longer-term development plans. Sour Gas leaks or other exposure to Sour Gas produced from the Company's properties may result in damage to equipment, an evacuation of populated areas, liability to third parties, adverse effects to humans and animals, including bodily harm and loss of life, or the environment, or the shutdown of operations, all of which could result in liability to the Company. Special equipment and operating procedures are deployed by the industry for the production of Sour Gas in accordance with applicable regulatory requirements.

The Company is exposed to project risks in the execution of its business plan.

The Company manages a variety of small and large projects in the conduct of its business. Project delays may affect expected revenues from operations. Significant project cost over-runs could make a project uneconomic.

The Company's ability to execute projects and market oil, condensate and other NGLs and natural gas will depend upon numerous factors beyond its control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil, condensate and other NGLs and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling, completion and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Company may be unable to execute projects on time, on budget or at all, and may not be able to profitably market the oil, condensate and other NGLs and natural gas that it produces.

Unless the Company replaces the reserves that it produces through exploration and development, its existing reserves and production will decline, which would adversely affect the Company's business, financial condition, results of operations and prospects.

Producing oil, condensate and other NGLs and natural gas reserves are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Exploration and development are the Company's main methods of replacing and expanding its asset base. The Company intends to dedicate the majority of its capital investment in the immediate future to further developing its core producing properties in the Grande Prairie area. The Company's exploration and development activities in these properties and other properties the Company pursues in the future may not be successful for various reasons. Exploration activities involve numerous risks, including the risk that no commercially productive reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and tying-in wells are often uncertain. The Company's exploration and development operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

- inadequate capital resources;
- lack of acceptable prospective leased acreage;
- mechanical difficulties such as major natural gas plant and regional pipeline failures;
- unexpected drilling conditions;
- pressure or irregularities in formations including higher than expected concentrations of H₂S gas;
- equipment failures or accidents;
- lack of storage;
- weather conditions;
- title problems;
- compliance with governmental regulations or required regulatory approvals;
- inadequate access to natural gas gathering and processing infrastructure and capacity;
- unavailability or high cost of drilling rigs, equipment or labour;
- approvals of third parties;

- reductions in oil, NGLs or natural gas prices; and
- limitations in the market for oil, condensate and other NGLs or natural gas.

The Company may be unable to execute its plans to acquire and develop properties in the Grande Prairie area. The Company may not be able to develop, find or acquire additional reserves to replace its current and future production at acceptable costs, which would adversely affect its business, financial condition and results of operations.

All of the Company's properties are located in the Pipestone Montney region, making the Company vulnerable to risks associated with having its production concentrated in that area.

All of the Company's producing properties are geographically concentrated in the Pipestone Area. As a result of this concentration, the Company may be disproportionately exposed to the impact of delays or interruptions of production from that area caused by significant governmental regulation and taxation in Alberta, transportation capacity constraints, curtailment of production, natural disasters, availability of equipment, facilities or services, adverse weather conditions, forest fires or other fires, the potential impact of climate change on the Pipestone Area or other events which impact that area. Due to the concentrated nature of the Company's portfolio of properties, all of the Company's properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on the Company's results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Impact of the COVID-19 Pandemic and Risks Related Thereto

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide could have an adverse impact on our business, including changes to the way the Company and its counterparties operate, and on the Company's financial results and condition. The COVID-19 pandemic, given its severity and scale, continues to adversely affect our business to varying degrees and many of its customers and business partners and also continues to pose risks to the global economy and the oil and natural gas industry more broadly. At the onset of the COVID-19 pandemic in March 2020, governments and regulatory bodies in affected areas imposed a number of measures designed to contain the COVID-19 pandemic, including widespread business closures, social distancing protocols, travel restrictions, quarantines, curfews and restrictions on gatherings and events. While many of the containment measures have been and continue to be eased or lifted across many parts of the world, additional safety precautions and operating protocols aimed at containing the spread of COVID-19 have been and continue to be instituted in line with guidance of public health authorities. Additional waves of the COVID-19 pandemic, together with the emergence of new COVID-19 variant strains, have led to the imposition of containment measures to varying degrees in many regions within Canada and globally. These containment measures continue to impact global economic activity, including the ability to move towards full recovery of the global economy and such measures also contribute to the decreased demand for hydrocarbons, increased market volatility and continued changes to the macroeconomic environment. As the impacts of the COVID-19 pandemic continue to materialize, the prolonged effects of the disruption have had and continue to have adverse impacts on our business strategies and initiatives, resulting in ongoing effects to our financial results, including the increase of counterparty, market and operational risks. Low prices for crude oil, NGLs and natural gas would reduce the Company's cash flow from operating activities and impact the Company's level of capital investment and may result in the reduction of production at certain producing properties.

While the duration and full impact of the COVID-19 pandemic is not yet known, the effects of COVID-19 may also include disruptions to production operations, access to materials and services, increased employee absenteeism from illness and temporary closures of the Company's facilities. The ultimate impacts will depend on future developments that are highly uncertain and cannot be predicted, including the scope, severity, duration and additional subsequent waves of the COVID-19 pandemic, including the introduction of new variants, as well as the effectiveness of actions and measures taken by the various levels of government. Despite recent positive vaccine developments, the ongoing evolution of the development and distribution of effective vaccines, recommendation and availability of subsequent vaccine doses and the availability of efficient and accurate testing options also continues to raise uncertainty.

The possibility of additional subsequent waves, and introduction of new variants, or further diseases emerge that give rise to similar effects, the adverse impact on the economy could deepen and result in further volatility and declines in commodity and financial markets. Moreover, it remains uncertain how the macroeconomic environment will be impacted following the COVID-

19 pandemic. Unexpected developments in commodity and financial markets, regulatory environments, industrial activity or consumer behavior and confidence may also have adverse impacts on the Company's business and financial condition, potentially for a substantial period of time.

Unforeseen title defects may result in a loss of entitlement to production and reserves.

Ownership of some of the Company's properties could be subject to prior undetected claims or interests. The Company conducts title reviews from time to time according to industry practice prior to the purchase of most of its oil and natural gas producing properties or the commencement of drilling wells. However, title reviews, if conducted, do not guarantee that an unforeseen defect in the chain of title will not arise to defeat a claim by the Company. If any such defect were to arise, the Company's entitlement to the production and reserves associated with such properties could be jeopardized, and could have a material adverse effect on the Company's business, financial condition, results of operations and prospects and the Company's ability to execute its business plan in a timely manner. Indigenous groups have claimed title and rights to portions of Western Canada. The Company is not aware of any significant claims that have been made in respect of its property and assets; however, if a significant claim arose and was successful, this could have an adverse effect on the Company and its operations.

The Company's permits, licenses and mineral rights may be subject to challenges by Indigenous groups.

Certain Indigenous groups may have rights in relation to the Company's permit and leased lands in Alberta and other lands that are potentially affected by the Company's activities. The Governments of Canada and Alberta have a duty to consult with Indigenous groups in relation to actions and decisions which may impact those rights and claims and, in certain cases, have a duty to accommodate their concerns. These duties have the potential to adversely affect the Company's ability to obtain permits, leases, licenses and other approvals, or to meet the terms and conditions of those approvals. The scope of the duty to consult by the federal Government of Canada and the Government of Alberta is subject to ongoing litigation which may result in uncertainty with respect to the process to obtain permits, leases, licenses and other approvals. Opposition by Indigenous groups may also negatively impact the Company in terms of public perception, diversion of management time and resources, legal and other advisory expenses, potential blockades or other interference by third parties in the Company's operations, or court-ordered relief impacting the Company's operations. Challenges by Indigenous groups could adversely impact the Company's progress and ability to explore and develop its properties.

Abandonment and reclamation costs are difficult to estimate reliably and the accrued liabilities in respect of such costs may not be sufficient.

The Company will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which may result in the future substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of the Company's approvals and legislation may result in the imposition of fines and penalties, which may be material, or suspensions or the revocation of the right to operate. Generally, abandonment and reclamation costs can be substantial and, while the Company provides for a decommissioning provision liability in its financial statements for such costs in accordance with IFRS, no assurance can be given that such provisions will be sufficient. It is not possible at this time to estimate abandonment and reclamation costs reliably since they will, in part, depend on future regulatory requirements. In addition, in the future, the Company may determine it prudent or be required by applicable laws, regulations or regulatory approvals to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs. If the Company establishes a reclamation fund, its liquidity and cash flow may be adversely affected.

The Company's development and exploratory drilling efforts and its well operations may not be profitable or achieve the Company's targeted returns.

The Company has acquired and may in the future acquire significant amounts of unproved property in order to further its development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. The Company acquires unproved properties and leases undeveloped acreage that the Company believes will enhance its growth potential and increase its earnings over time. However,

the Company can provide no assurance that all prospects will be economically viable or that the Company will not abandon its investments. Additionally, the Company can provide no assurance that unproved property acquired by the Company or undeveloped acreage leased by the Company will be profitably developed, that new wells drilled by the Company in prospects that it pursues will be productive or that the Company will recover all or any portion of its investment in such unproved property or wells.

Drilling for oil, condensate and other NGLs and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs and provide an acceptable return on investment. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or cancelled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. In addition, wells that are profitable may not meet the Company's internal return targets, which are dependent upon the current and expected future market prices for oil, condensate and other NGLs and natural gas, expected costs associated with producing oil, condensate and other NGLs and natural gas and the Company's ability to add reserves at an acceptable cost. Drilling results in the Company's prospective oil and liquids-rich natural gas properties may be more uncertain than those for shale plays that are more developed and have longer established production histories, and the Company can provide no assurance that drilling and completion techniques that have proven to be successful in other shale formations to maximize recoveries will be ultimately successful when used in newly developed shale or tight gas formations.

Part of the Company's strategy involves exploratory drilling using the latest available horizontal drilling and completion techniques; therefore, the results of the Company's planned exploratory drilling activities are subject to drilling and completion technique risks and drilling results may not meet the Company's expectations for reserves or production.

The Company's operations involve utilizing the latest drilling and completion techniques as developed by the Company and its service providers. Risks that the Company faces while drilling include, but are not limited to, landing its well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running its casing the entire length of the well bore, being able to run tools and other equipment consistently through the horizontal well bore and adequately cementing casing in place. Extreme heat, pressure and/or bacteria content could cause a failure in the Company's casing liners, which could result in reduced well performance. Risks that the Company faces while completing its wells include, but are not limited to, being able to hydraulically fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. Wells also can come into communication with one another as a result of the Company's chosen well spacing or due to subsurface geological features in the course of the Company's drilling and completions operations and, in some instances, this could potentially lead to reduced recoverability. The results of the Company's drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and consequently the Company is less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If the Company's drilling results are less than anticipated or the Company is unable to execute its drilling program because of capital constraints, lease agreement expirations, access to gathering systems, and/or natural gas and oil price declines, the return on the Company's investment in these areas may not be as attractive as it anticipates. Further, as a result of any of these developments the Company could incur material write-downs of its oil and natural gas properties and the value of the Company's undeveloped acreage could decline in the future.

The Company has limited intellectual property protection for its operating practices and depends on the expertise of its employees and contractors.

The Company uses operating practices that the Company believes are of significant value in developing its business. In particular, the Company believes that its drilling, completion and production techniques related to multilateral development wells, integration of infrastructure and other aspects of its business have to date, or may, provide it with a competitive advantage. In

most cases, patent or other intellectual property protection is unavailable for these practices. The Company's use of independent contractors in most aspects of its drilling and completion operations makes the protection of such technology more difficult. Moreover, the Company relies on the technological and practical expertise of the independent contractors that it retains for its operations. The Company has no long-term agreements with these contractors, and thus it cannot be sure that it will continue to have access to this expertise or that the cost to retain these contractors will remain constant, particularly if the demand for contractors increases with the potential strengthening of oil, condensate and other NGLs and natural gas prices. In addition, public record laws in Alberta do not provide confidentiality for the Company's specific industry practices and materials for more than one year with respect to exploratory wells and more than one month with respect to the Company's development wells. As a result, the Company's competitors may be able to take advantage of expertise that the Company has developed and the Company will not be able to prevent them from doing so, which could reduce its competitive advantage.

Third parties may make claims regarding the Company's rights to use the techniques and equipment the Company employs.

Claims made by third parties regarding the Company's rights to use the techniques and equipment that the Company employs could, among other things, delay or prevent the exploration or development of the Company's properties, which in turn could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Certain of the Company's undeveloped leasehold acreage is subject to agreements that may expire in the near future.

As of December 31, 2022, the Company held Crown petroleum and natural gas licenses and leases on over 141 net Montney sections of land. Under the terms of the Crown licenses and leases which govern these properties, unless the Company drills to validate lands, proves lands to be productive or establishes commercial production on the properties that are subject to the licenses and leases during their term, the licenses and leases will expire. There can be no assurance that any of the obligations required to maintain each agreement will be met. Continuations of expiring non-producing licenses and leases are reviewed by the Alberta Department of Energy, on a case by case basis. A continuation of an operated license or lease is generally applied for if licenses validated through drilling or technical data demonstrate the possibility of a productive license or lease in the near-term. If the Company's licenses and leases expire and the Company cannot obtain a lease continuation from the Alberta Department of Energy, the Company would lose its right to develop the related properties unless it subsequently nominates and successfully repurchases the impacted licenses and leases from the Government of Alberta.

Properties the Company has acquired and may acquire in the future may not produce as projected, and the Company may be unable to determine reserve potential, identify liabilities associated with the properties that the Company acquires or obtain protection from sellers against such liabilities.

Acquiring oil, condensate and other NGLs and natural gas properties requires the Company to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, the Company performs a review of the subject properties, but such a review will not reveal all existing or potential problems, nor will it permit the Company to become sufficiently familiar with the properties to fully assess their deficiencies. In the course of its due diligence, the Company may not inspect every well or pipeline. The Company cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. Even if problems are identified, the Company may not be able to obtain contractual indemnities from the seller for liabilities created prior to the Company's purchase of the property. The Company may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with its expectations.

The Company's operations are subject to various governmental regulations which require compliance that can be burdensome and expensive.

The Company's oil, condensate and other NGLs and natural gas operations are subject to various federal, provincial and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include the requirements surrounding facility and lease construction, discharge permits for drilling

operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil, condensate and other NGLs and natural gas wells below actual production capacity to conserve supplies of oil, condensate and other NGLs and natural gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil, condensate and other NGLs and natural gas, by-products thereof and other substances and materials produced or used in connection with oil, condensate and other NGLs and natural gas operations are subject to regulation under federal, provincial and local laws and regulations primarily relating to protection of human health and the environment. Failure to comply with laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, permit revocations, requirements for additional pollution controls and injunctions limiting or prohibiting some or all of the Company's operations. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management. The Company may incur significant expenditures and experience delays in order to maintain compliance with governmental laws and regulations applicable to it. Failure to comply with such laws and regulations could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Provincial laws and regulations are a significant factor in the profitability of oil, condensate and other NGLs and natural gas production in Canada and changes to these regimes and/or in their interpretation and enforcement could adversely affect the Company's profitability.

The Company's business may be adversely impacted by changes to the interpretation and enforcement of laws and regulations related, but not limited, to land tenure, industry activity level, environmental impact, access to the Company's properties, well classification, volumetric reporting, operating standards and facility requirements.

In addition, the Company's business may be adversely impacted by changes in provincial royalty regimes and/or their interpretation and enforcement. In Alberta, most of the production of oil, condensate and other NGLs and natural gas is subject to Crown lessor royalties that must be paid to the provincial government. The majority of Pipestone Energy's wells have been drilled under the Alberta Modernized Royalty Framework.

The Company's operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety concerns and requirements that are applicable to the Company's business activities.

The Company may incur significant delays, costs and liabilities as a result of federal, provincial and local environmental, health and safety requirements applicable to the Company's exploration, development and production activities. These laws and regulations may require the Company to obtain a variety of permits or other authorizations governing its air emissions, water discharges, earth movement, waste disposal or other environmental impacts associated with drilling, producing and other operations; regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or impose substantial liabilities for spills, pollution or failure to comply with regulatory obligations. In addition, these laws and regulations may restrict the rate of oil, condensate and other NGLs and natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with laws and regulations may result in the assessment of administrative, regulatory, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Under certain environmental laws that impose strict as well as joint and several liability, the Company may be required to remediate contaminated properties currently or formerly operated by the Company or facilities of third parties that received waste generated by the Company's operations regardless of whether such contamination resulted from the conduct of others or from consequences of the Company's own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of the Company's operations. In addition, the risk of accidental spills or releases from the Company's operations could expose it to significant liabilities under environmental laws. Moreover, public interest in the protection of the

environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry is likely to continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, the Company's business, financial conditions, results of operations and prospects could be materially adversely affected. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

The Company has not established a separate reserve fund for the purpose of funding its estimated future environmental, including reclamation and abandonment, obligations. As a result, the Company may not be able to satisfy these obligations. Any site reclamation or abandonment costs incurred in the ordinary course in a specific period will be funded out of the Company's cash flow from operations or from its other sources of available funding. If the Company is unable to fully fund the cost of remedying an environmental obligation, it might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy, which could have an adverse effect on the Company's financial condition and results of operations.

Oil and natural gas companies operating in Alberta are subject to significant regulation with respect to their employees' health and safety. Companies are required to self-report accidents and infractions, and regular and random audits of operations are also part of the regulatory process. Previous violations of the same requirement are taken into account when assessing penalties and subsequent behavior may be subjected to escalating levels of oversight and loss of operating freedom. Non-compliance with regulations may in the future result in suspension or closure of the Company's operations or the imposition of other penalties against the Company.

There is also a risk that Pipestone Energy could face litigation initiated by third parties relating to climate change or environmental regulations.

Restrictions on operational activities intended to protect certain species of wildlife may adversely affect the Company's ability to conduct drilling and other operational activities in some of the areas where it operates.

Oil, condensate and other NGLs and natural gas operations in the Company's operating areas can be adversely affected by seasonal or permanent restrictions on construction, drilling and well completions activities designed to protect various wildlife. Seasonal restrictions may limit the Company's ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling and completions activities are allowed. These constraints and the resulting shortages or high costs could delay the Company's operations and materially increase the Company's operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit development in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species as threatened or endangered in areas where the Company operates could cause the Company to incur increased costs arising from species protection measures or could result in limitations on the Company's exploration and production activities that could have an adverse impact on the Company's ability to develop and produce its reserves.

Some of the Company's directors and officers have conflicts of interest as a result of their involvement with other firms or companies.

Certain of the Company's directors and officers are also directors and officers of other firms or companies and conflicts of interest may arise between their duties as officers and directors of Pipestone Energy and as officers and directors of such other companies. To the extent that such other companies may participate in ventures in which the Company may participate, or in ventures which the Company may seek to participate, the Company's directors and officers may have a conflict of interest in negotiating and concluding terms respecting the extent of such participation and will be subject to and governed by the procedures prescribed in the ABCA. In all cases where the Company's directors and officers have an interest in other companies, such other companies may also compete with the Company for the acquisition of oil and natural gas properties. Such conflicts of the Company's directors and officers may result in a material and adverse effect on the Company's profitability, results of operation and financial condition. As a result of these conflicts of interest, the Company may miss the opportunity to participate

in certain transactions, which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Actual results may differ materially from management estimates and assumptions.

In preparing consolidated financial statements in conformity 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 fair values, income taxes, share-based compensation, contingent liabilities 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 Company's business, financial condition, results of operations and prospects.

The Company's activities are affected by seasonality.

The level of activity in the Canadian oil, condensate and other NGLs and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, although not a condition faced by the Company today, certain production areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of the Company's exploration and development activities, which could in turn have a material adverse impact on the Company's business, operations and prospects.

The Company may be affected by alternatives to and changing demand for petroleum products.

Fuel conservation measures, alternative fuel requirements, increasing investor and consumer demand for alternatives to oil, condensate and other NGLs and natural gas, and technological advances in fuel economy and energy generation and storage devices could reduce the demand for fossil fuels. Any technological advances that would allow bitumen produced by the Alberta oil sands to be transported with less condensate, to be transported in a solid state or by utilizing recycled condensate, as contemplated by diluent recovery unit projects under construction or in the planning phase in Alberta, could reduce the demand for the Company's condensate production. The Company cannot predict the impact or pace of changing demand for oil, condensate and other NGLs and natural gas products or the impacts on the demand for oil, condensate and other NGLs and natural gas products as a result of climate change, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The Company faces extensive competition in its industry.

The oil, condensate and other NGLs and natural gas industry is intensely competitive, and the Company competes with other companies that have greater resources. Many of these companies not only explore for and produce oil, condensate and other NGLs and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. Their competitive advantages may negatively impact the Company's ability to acquire prospective properties, develop reserves, attract and retain quality personnel and raise capital. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil, condensate and other NGLs and natural gas prices and production, the availability of alternative energy sources and the application of government regulation.

The Company may be exposed to third-party credit risk.

The Company may be exposed to third-party credit risk through its contractual arrangements with its current or future joint interest partners, customers, midstream processing and transportation providers, counterparties related to risk management contracts, suppliers and other parties. In the event such entities fail to meet their contractual obligations to Pipestone Energy, such failures could have a material adverse effect on Pipestone Energy's business, financial condition, results of operations and prospects.

The Company depends upon a limited number of customers for the sale of most of its oil, condensate and other NGLs and natural gas production. The loss of one or more of these purchasers or the security of such purchase contracts could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The availability of a ready market for oil, condensate and other NGLs and natural gas the Company produces depends on numerous factors beyond the control of the Company's management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of pipelines, the availability of skilled labour, materials and equipment, the effect of provincial and federal regulation of oil, condensate and other NGLs and natural gas production and federal regulation of natural gas sold in interprovincial commerce. The Company may not continue to have ready access to suitable markets for its future oil, condensate and other NGLs and natural gas production. To the extent any significant customer reduces the volume of its oil, condensate and other NGLs and natural gas purchases from the Company, the Company could experience a temporary interruption in sales of, or a lower price for, its oil, condensate and other NGLs and natural gas production and its revenues could decline.

The Company is exposed to risks of loss in the event of non-performance by its customers. Some of the Company's customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Even if the Company's credit review and analysis mechanisms work properly, the Company may experience financial losses in its dealings with other parties. Any unanticipated increase in the nonpayment or non-performance by the Company's customers and/or counterparties could adversely impact the Company's cash flow.

Lower oil, condensate and other NGLs and natural gas prices and higher costs increase the risk of write-downs of the Company's oil and natural gas property assets.

Under IFRS, when indicators of impairment exist, the carrying value of the Company's property, plant and equipment and exploration and evaluation assets is compared to its recoverable amount. The recoverable amount is defined as the higher of the fair value less cost to sell or value in use. A decline in oil, condensate and other NGLs and natural gas prices may be an indicator of impairment and may result in a write-down of the value of the Company's assets. While these write-downs would not affect cash flow from operations, the charge to earnings may be viewed unfavorably in the market. Property, plant and equipment or exploration and evaluation asset write-downs may also be reversed to earnings in future periods should the conditions that caused impairment reverse.

The Company's use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of oil, condensate and other NGLs and natural gas, which could adversely affect the results of the Company's drilling operations.

Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to ascertain all subsurface reservoir characteristics or know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3D seismic and other advanced technologies requires greater pre-drilling investments than traditional drilling strategies, and the Company could incur losses as a result of such investments. As a result, the Company's drilling activities may not be successful or economical.

The Company has entered into commodity price hedging instruments and may in the future enter into additional contracts for a

portion of its production, which may result in the Company making cash payments or prevent the Company from receiving the full benefit of increases in prices for oil, condensate and natural gas.

To mitigate the effects of commodity price fluctuations, the Company is party to commodity price hedging instruments in the form of various option based and swap transactions. Such arrangements may expose the Company to risk of financial loss in certain circumstances, including instances where production is less than expected or oil, condensate and natural gas prices increase. In addition, these arrangements may limit the benefit to the Company of increases in the price of oil, condensate and natural gas. The Company can provide no assurance that the hedging transactions it has entered into, or will enter into, will adequately protect the Company from fluctuations in oil, condensate and natural gas prices.

A terrorist attack or armed conflict could harm the Company's business.

Terrorist activities (including environmental terrorism), anti-terrorist efforts and other armed conflicts involving Canada, the U.S. or other countries may adversely affect the Canadian, U.S. and global economies and could prevent the Company from meeting its financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil, condensate and other NGLs and natural gas, potentially putting downward pressure on demand for the Company's products and causing a reduction in the Company's revenues. Oil, condensate and other NGLs and natural gas related facilities could be direct targets of terrorist attacks, and the Company's operations could be adversely impacted if infrastructure integral to the Company's customers' operations is destroyed or damaged.

The Company's information assets and critical infrastructure may be subject to cyber security risks.

The Company is subject to a variety of information technology and system risks, including potential breakdown, hijacking, destruction or interruption of the Company's information technology systems caused by third parties or insiders, as well as cyber-attacks, cyber-fraud, viruses or malware infections in emails, websites, or removable media, and social engineering activities like phishing and employee impersonation. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to its business activities or its competitive position. In addition, cyber-phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Company becomes a victim to a cyber-phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information or could result in a loss of control of the Company's technological infrastructure or financial resources.

Although the Company has security measures and controls in place that are designed to mitigate these risks, a breach of these security measures or controls could occur and result in losses of material or confidential information, reputational consequences, financial damages, breaches of privacy laws, higher insurance premiums, plant and utility outages, damage to assets, releases or spills of toxic substances, safety issues, operational downtime or delays and/or production and revenue losses. 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, results of operations and prospects.

Loss of the Company's information and computer systems could adversely affect the Company's business.

The Company is dependent on its information systems and computer-based programs, including its well/field operations information, seismic data, land data, electronic data processing and financial data. If any of such programs or systems were to fail or create erroneous information in the Company's hardware or software network infrastructure, possible consequences include a loss of communication links, inability to find, produce, process and sell oil, condensate and other NGLs and natural gas and an inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Breaches of Confidentiality.

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to its business, operations or affairs. Although confidentiality agreements are generally signed by third parties prior to the disclosure of confidential information, a breach could put the Company at competitive risk and may cause significant damage to its business. The harm to the Company's business from a breach of confidentiality cannot presently be quantified but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Company will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to our business that such a breach of confidentiality may cause.

The Company may be unable to dispose of non-strategic assets on attractive terms and may be required to retain liabilities for certain matters.

The Company's ability to dispose of non-strategic assets, such as acreage that it does not intend to place on its drilling schedule prior to lease expirations, could be affected by various factors, including the availability of purchasers willing to purchase non-strategic assets at prices acceptable to the Company. Sellers typically retain certain liabilities or agree to indemnify buyers for certain matters. The magnitude of such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release the Company from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, the Company may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations. Currently, the Company has very minimal non-strategic assets that pose this risk.

The Company's operations may be negatively impacted by changes to provincial liability management programs.

Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Alberta and the AER continues to implement its AB LMF, completing the remaining amendments to the necessary directive and regulations to entirely phase-out the AB LMR Program. The implementation of the AB LMF or other changes to the requirements of liability management programs may result in significant increases to the security that must be posted by the Company, increased and more frequent financial disclosure obligations or may result in the denial of licence or permit transfers, which could impact the availability of capital to be spent by the Company which could in turn materially adversely affect the Company's business and financial condition. The impact and consequences of the SCC's Redwater decision on the AER's rules and policies, lending practices in the petroleum and natural gas industry and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMF may prevent or interfere with the Company's ability to acquire or dispose of assets, as both the vendor and the purchaser of crude oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets.

Changes to royalty regimes may negatively impact the Company.

There can be no assurance that the governments in the jurisdictions in which the Company has assets will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of third-party projects on the Royalty Properties. An increase in royalties could impact the financial condition of third parties operating on the Company's properties impacting future capital investment which could reduce the Company's business, financial condition, results of operations and prospects. See "*Industry Conditions – Royalties and Incentives*".

Reassessment of the Company's prior transactions and tax filings could subject the Company to higher than expected past or future tax liability, interest or penalties. Changes to tax laws, or the interpretation thereof, may have a detrimental effect on the Company.

Pipestone Energy and its predecessor's income tax returns are subject to reassessment by the applicable taxation authority and it is possible that the tax authorities could successfully challenge any prior transactions and tax filings of Pipestone Energy and/or its predecessors. In the event of a successful reassessment, Pipestone Energy may be subject to higher than expected past or future income tax expenses as well as potential interest and penalties which could have a material and adverse financial impact on its operations.

Income tax laws, including income tax laws applicable to the oil and natural gas industry such as the treatment of resource taxation, taxation on future share buy backs or dividends, and government incentive programs relating to the oil and natural gas industry, may in the future be changed or interpreted in a manner that adversely affects Pipestone Energy. Furthermore, tax authorities having jurisdiction over the Company may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's detriment.

Variations in foreign exchange rates and interest rates could negatively impact the Company's production revenues, the value of the Company's reserves and the Company's cost of debt.

World oil, condensate and other NGLs and natural gas prices are quoted in U.S. dollars. The Canadian/U.S. dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers for oil, condensate and other NGLs and natural gas. Material fluctuations in the value of the Canadian dollar can have a negative impact on the Company's production revenues. Future Canadian/U.S. dollar exchange rates could accordingly affect the future value of the Company's reserves as determined by independent evaluators.

To the extent that the Company engages in risk management activities related to commodity prices and foreign exchange rates, there is a credit risk associated with counterparties with which it may contract.

An increase in interest rates could result in an increase in the amount Pipestone Energy pays to service debt, primarily on its RBL, resulting in a reduced amount available to fund its exploration and development activities, and as applicable, the cash available for any future returns of capital to shareholders, such as share buybacks and/or dividends, and could negatively impact the market price of its Common Shares.

The Company's insurance policies may not be sufficient to cover the full extent of the risks to which the Company is exposed.

The Company's involvement in the exploration for and development of oil, condensate and other NGLs and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, leaks of Sour Gas, property damage, personal injury or other hazards. Although the Company maintains insurance generally in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities or may not be collectible in a reasonable timeframe. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The Company may become involved in litigation which could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

In the normal course of Pipestone Energy's operations, it may become involved in, named as a party to, or be the subject of various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, petroleum and natural gas rights, surface rights, the environment and contract disputes. The

outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to Pipestone Energy and as a result, could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Non-IFRS measures included in this AIF are based upon variable components and future calculations may vary.

This AIF has references to certain non-IFRS measures. These non-IFRS measures and other financial estimates of management are based upon variable components. There can be no assurance that these components and future calculations of non-IFRS measures will not vary.

Breach by a third-party of its obligations to the Company could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

While discussing potential business relationships or other transactions with third parties, Pipestone Energy may disclose confidential information relating to its business, operations or affairs. Although confidentiality agreements may be signed by third parties prior to the disclosure of confidential information, a breach could put Pipestone Energy at competitive risk and may have a material adverse effect on its business. The harm to Pipestone Energy's business from a breach of confidentiality cannot presently be quantified but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, Pipestone Energy will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause. There is also a risk that third parties may breach other types of agreements with Pipestone Energy and there may be enforceability issues in some of the Company's contracts. This could have a material adverse effect on the Company, and it may not be adequately compensable in damages.

Future expansion by the Company into new activities may change the Company's risk exposure.

Pipestone Energy's operations and the expertise of its management are currently focused primarily on oil, condensate and other NGLs and natural gas production, exploration and development in the Pipestone Area. In the future the Company may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase its exposure to one or more existing risk factors, which may in turn result in the future operational and financial conditions of the Company being adversely affected.

The Company may not be able to respond quickly to competitive pressures to adopt new technologies which could have a materially adverse effect on the Company's business, financial condition, results of operations and prospects.

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

Estimates of oil, NGLs and natural gas reserves and production therefrom are uncertain and may vary substantially from actual production.

There are numerous uncertainties associated with estimating quantities of reserves and in projecting future rates of production and timing of expenditures. The reserves information herein represents estimates prepared by McDaniel with respect to certain of the Company's oil, NGLs (including condensate) and natural gas properties at December 31, 2021. Petroleum engineering is not an exact science. Information relating to the Company's oil, NGLs and natural gas reserves is based upon engineering estimates which may ultimately prove to be inaccurate. Estimates of economically recoverable oil, NGLs and natural gas reserves and of

future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, assumptions concerning commodity prices, the quality, quantity and interpretation of available relevant data, future site restoration and abandonment costs, the assumed effects of regulations by governmental agencies and assumptions concerning future oil, NGLs and natural gas prices, future operating costs, royalties, severance and taxes, capital investments and workover and remedial costs, all of which may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil, NGLs and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different evaluators or by the same evaluators at different times may vary substantially. Actual production, revenues and expenses with respect to the Company's reserves will likely vary from estimates, and such variances may be material. In particular, there can be no assurance that the Company will achieve the production estimates for 2022 set forth in the McDaniel Reserves Report. See "*Statement of Reserves Data – Other Oil and Natural Gas Information – Production Estimates*".

The present value of future net revenues from the Company's reserves is not necessarily the same as the current market value of the Company's estimated oil, NGLs and natural gas reserves. The Company bases the estimated discounted future net revenue from its reserves on, among other things, forecast prices and costs, the capital investments described in the McDaniel Reserves Report, applicable royalties and operating costs and other factors.

However, actual future net revenues from the Company's oil, NGLs and natural gas properties also will be affected by factors such as:

- the actual prices the Company receives for oil, NGLs and natural gas;
- the amount and timing of actual production;
- supply of and demand for oil, NGLs, and natural gas; and
- changes in governmental regulations or taxation.

The timing of both the Company's production and its incurrence of costs in connection with the development and production of oil, NGLs and natural gas properties will affect the timing of actual future net revenues from the Company's reserves, and thus their actual present value. In addition, the discount factor the Company uses when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and natural gas industry in general.

As of December 31, 2021, approximately 72% of the Company's estimated gross proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital investments and successful drilling operations. The reserves data described herein assumes that the Company can and will make these investments and conduct these operations successfully, but these assumptions may not be accurate, and this may not occur. The Company's actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

Global advancement of alternative energy sources could negatively impact the Company's long-term viability.

Globally, there is an increasing focus on transitioning to a low-carbon economy resulting in a number of policies and initiatives designed to shift resources and investment away from fossil fuels towards low carbon sources. This includes various government regulations that restrict the production and consumption of fossil fuels such as zero emission vehicle mandates, prohibitions on plastic use, and fuel efficiency standards. Government subsidies directed towards new low-carbon technologies or to businesses providing products and services that reduce consumer demand for fossil fuels may also result in a broader reduction in the global economy's reliance on fossil fuels. In addition, shifting consumer preferences towards low-carbon products and services are also driving investment in technologies and products that reduce fossil fuel consumption.

The global advancement of alternative sources of energy that are not sourced from fossil fuels could affect the profitability and eventually the viability of the Company's future development activities or exploration prospects. The timing and extent to which global energy markets transition from carbon-based sources to alternative energy is highly uncertain. The energy transition could impact the future prices of commodities. Pricing assumptions used in the determination of reserves and future net revenue

estimates incorporates markets expectations and the evolving worldwide demand for energy but may prove inaccurate. The Company is constantly evaluating its options with respect to increasing environmental efficiency through its operations. However, there can be no assurances that the Company will be able to predict any such market trends or consumer preferences. Accordingly, there is a risk that the nature of the global energy transition materially adversely affects the Company's business and financial condition.

Shareholders in the United States have a limited ability to enforce civil remedies against the Company in Canada.

The Company is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. All of our directors, except for three, all of our officers, all of our assets and all or a substantial portion of the assets of such persons are located outside the U.S. As a result, it may be difficult for investors in the U.S. to effect service of process within the U.S. upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the U.S. courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the U.S.. There is doubt as to the enforceability in Canada against the Company or against any of our directors, officers or representatives of experts who are not residents of the U.S., in original actions or in actions for enforcement of judgments of U.S. courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the U.S.

The Company faces compliance and supervisory challenges in respect of the use of social media as a means of communicating with clients and the general public.

Increasingly, social media is used as a vehicle to carry out cyber-phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into the Company's systems and obtain confidential information. The Company periodically reviews, supervises, retains and maintains the ability to retrieve social media content. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Company may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

Forward-looking information may prove inaccurate.

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

Significant Shareholder Influence on the Company

Riverstone, GMT Capital and Al Mehwar are significant shareholders of the Company. As at the date hereof, to the Company's knowledge, Riverstone holds 106,151,583 Common Shares or 38.0% of the issued and outstanding Common Shares, GMT Capital holds 37,675,762 Common Shares or 13.5% of the issued and outstanding Common Shares and Al Mehwar holds 31,439,809 Common Shares or 11.3% of the issued and outstanding Common Shares.

Additionally, each of Riverstone Pipestone LP, GMT Capital and Al Mehwar are entitled to nominate an individual(s) to the Board pursuant to the Riverstone Nomination Agreement, the GMT Capital Nomination Agreement and the Al Mehwar Nomination Agreement, respectively.

Pursuant to the Riverstone Nomination Agreement, Riverstone Pipestone LP has the right to nominate: (a) two directors for election to the Board so long as it holds in excess of 20% of the issued and outstanding Common Shares; or (b) one director for election to the Board so long as it holds at least 10% of the issued and outstanding Common Shares. Currently, Riverstone Pipestone LP is represented by Messrs. Robert Tichio and Jesal Shah on the Board.

Pursuant to the GMT Capital Nomination Agreement and the Al Mehwar Nomination Agreement, each of GMT Capital and Al

Mewhar have the right to nominate one director for election to the Board so long as each of GMT Capital and Al Mewhar hold at least 10% of the Common Shares. Currently, GMT Capital is represented by William Lancaster and Al Mehwar is represented by Paul Wanklyn.

As such, the Company's significant shareholders will have, subject to applicable law, the ability to determine the outcome of certain matters submitted to shareholders and/or the Board for approval, including, but not limited to, the approval of significant corporate matters, election of directors of the Company and the approval of certain transactions. Pipestone Energy's interests and those of its significant shareholders may at times conflict, and such conflict may be resolved against Pipestone Energy or its minority shareholders' interests.

Dispositions by a significant shareholder could have an adverse effect on the market price of the Common Shares. As a result of the significant holdings, there is a risk that the Common Shares may be less liquid and may trade at a relative discount compared to circumstances where a significant shareholder does not have the ability to influence or determine matters affecting the Company. Additionally, there is a risk that the significant shareholders' interests in the Company may discourage transactions involving a change of control, including transactions in which minority shareholders of the Company might otherwise receive a premium for their securities in the Company over the then-current market price.

See "Description of Capital Structure" and "Material Contracts" in this AIF for more information.

Risks Related to the Common Shares

The price of the Common Shares could be volatile.

A number of factors could influence the volatility in the trading price of the Common Shares, including changes in the economy or in the financial markets, industry related developments, increased public pressure for institutional investors to divest from fossil fuel companies, and the impact of changes in the Company's daily operations. Each of these factors could lead to increased volatility in the market price of the Common Shares. In addition, variations in the Company's earnings estimates, production estimates or other financial or operating metrics by securities analysts and the market prices of the securities of the Company's competitors may also lead to fluctuations in the trading price of the Common Shares.

There may be no return on investment in the Common Shares.

There is no assurance that the business of the Company will be operated successfully, or that the business will generate sufficient income to allow investors to recoup all or any portion of their investment. There is no assurance that an investment in the Common Shares will earn a specified rate of return or any return over the life of the investment. There is no assurance that the Common Shares of the Company will trade at a meaningful daily volume.

The Common Shares may be subject to further dilution and a significant number of Common Shares may be sold by shareholders.

The Company may make future acquisitions or enter into additional financings or other transactions involving the issuance of securities of the Company, which may be dilutive. No prediction can be made as to the effect, if any, such transactions will have on the market price of the Common Shares prevailing from time to time. The issuance or sale of a substantial number of the Common Shares in the public market, or the perception that such transactions may occur, could adversely affect the prevailing market price of the Common Shares and negatively impact the Company's ability to raise equity capital in the future. See "Description of Capital Structure" section below for details of Common Shares issued and potentially dilutive instruments.

The amount and frequency at which future cash dividends are paid may vary and there is no assurance that the Company will pay dividends in the future.

The amount of future cash dividends paid by the Company is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices; production levels; financial condition of the Company; results of operations; capital expenditure requirements; working capital

requirements; operating costs; current and expected future levels of earnings; liquidity requirements; market opportunities; income taxes; debt repayments; legal, regulatory and contractual constraints; the Company's risk management activities or programs; the Company's business plan, strategies and objectives; tax laws; foreign exchange rates; interest rates; and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which are beyond the control of the Company, the Company's dividend policy and, as a result, future cash dividends, could be reduced or suspended entirely, from time to time. The Fourth Amended and Restated Credit Agreement may prohibit the Company from paying dividends at any time at which a default or event of default has occurred and is continuing, or if a default or event of default would exist as a result of paying the dividend.

Over time, the Company's capital and other cash needs may change significantly from its current needs, which could affect whether the Company pays dividends and the amount of dividends, if any, it may pay in the future. If the Company continues to pay dividends at the current levels, it may not retain a sufficient amount of cash to finance external growth opportunities, meet any large unanticipated liquidity requirements or fund its activities in the event of a significant business downturn. The Board may amend, revoke or suspend the Company's dividend policy at any time. A decline in market price, liquidity, or both, of the Common Shares could result if the Company reduces or eliminates the payment of dividends, which could result in losses to shareholders.

The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Company and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which may result from lower commodity prices and any decision by the Company to finance capital expenditures using funds from operations.

To the extent that external sources of capital, including in exchange for the issuance of additional Common Shares, become limited or unavailable, the ability of the Company to make the necessary acquisitions to maintain or expand petroleum and natural gas reserves will be impaired. To the extent that the Company is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Variations in foreign exchange rates may affect the amount of cash dividends received by shareholders who receive dividends in currencies other than Canadian dollars.

The Company's cash dividends are declared in Canadian dollars and may be converted in certain instances to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, non-resident shareholders, and shareholders who calculate their return in currencies other than the Canadian dollar, are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to the shareholder's home currency.

Non-resident shareholders are required to pay additional taxes on their dividends.

Cash dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25% unless the rate is reduced under the provisions of an applicable double taxation treaty. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Where a non-resident is a United States resident entitled to benefits of the Canada-United States Income Tax Convention, 1980 and is the beneficial owner of the dividends then the rate of Canadian withholding tax is generally reduced to 15%. In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.

Risks Related to the Fourth Amended and Restated Credit Agreement

The Company may be unable to comply with its covenants under the Third Amended and Restated Credit Agreement or otherwise default on its obligations under the Third Amended and Restated Credit Agreement.

Pipestone Energy currently has an RBL under its Fourth Amended and Restated Credit Agreement in an aggregate maximum

principal amount of \$280.0 million, which is comprised of a \$250.0 million Senior Facility and a \$30.0 million Operating Line. The revolving period of the RBL currently ends on May 29, 2023 with an additional one-year term out period thereafter, which means that, unless extended pursuant to the extension provisions in the Fourth Amended and Restated Credit Agreement, any amounts outstanding under the RBL would have to be repaid and the commitments under the RBL would have to be cancelled prior to that term out date. The amounts available to the Company under the Fourth Amended and Restated Credit Agreement may not be sufficient for future operations, or the Company may not be able to obtain additional financing on economic terms attractive to it, if at all. In the event that the Fourth Amended and Restated Credit Agreement is not extended beyond the current term, indebtedness under the Fourth Amended and Restated Credit Agreement will be repayable upon the expiry of the term. The interest charged on the facilities under the Fourth Amended and Restated Credit Agreement is calculated based on a sliding scale ratio of the Company's Senior Debt to EBITDA³ (as those terms are defined in the Fourth Amended and Restated Credit Agreement). There is also a risk that the RBL under the Fourth Amended and Restated Credit Agreement will not be renewed for the same amount or on the same terms.

The Fourth Amended and Restated Credit Agreement contains certain customary covenants. Upon the occurrence of any event of default under the Fourth Amended and Restated Credit Agreement, Pipestone Energy's lenders could elect to declare all amounts outstanding, together with accrued interest, to be immediately due and payable and to terminate any commitments to extend further credit. If the lenders under the Fourth Amended and Restated Credit Agreement accelerate the payment of the indebtedness outstanding thereunder Pipestone Energy's assets may not be sufficient to repay in full that indebtedness and Pipestone Energy's other indebtedness. The restrictions in the Fourth Amended and Restated Credit Agreement may adversely affect Pipestone Energy's ability to finance its future operations and capital needs and to pursue available business opportunities. Moreover, any new indebtedness Pipestone Energy incurs may impose financial restrictions and other covenants on Pipestone Energy that may be more restrictive than the Fourth Amended and Restated Credit Agreement. The Company's indebtedness could materially and adversely affect it in a number of ways. For example, it could:

- increase the Company's vulnerability to general adverse economic and industry conditions;
- require the Company to dedicate a portion of its cash flow from operations to service payments on its indebtedness, thereby reducing the availability of cash flow to fund working capital, capital investments, development efforts, shareholder distributions and other general corporate purposes;
- limit the Company's flexibility in planning for, or reacting to, changes in its business and the industry in which it operates;
- place the Company at a competitive disadvantage compared to its competitors that have less debt;
- expose the Company to the risk of increased interest rates as the facilities under the Fourth Amended and Restated Credit Agreement are at variable rates of interest; and
- limit the Company's ability to borrow additional funds to meet its operating expenses and for other purposes.

The Company may not generate sufficient cash flow from operations and may not have available to it future borrowings in an amount sufficient to enable it to make payments with respect to its indebtedness or to fund its other capital needs. In these circumstances, the Company may need to refinance all or a portion of its indebtedness on or before maturity. Without such financing, the Company could be forced to sell assets or secure additional financing to make up for any shortfall in its payment obligations under unfavourable circumstances. However, the Company may not be able to raise additional capital or secure additional financing on terms favourable to it or at all, and the terms of the Fourth Amended and Restated Credit Agreement may limit its ability to sell assets and also restrict the use of proceeds from such a sale.

The lenders under the Fourth Amended and Restated Credit Agreement have security over substantially all present and after acquired personal and real property of the Company via a fixed and floating charge demand debenture in the amount of \$500 million. If the Company becomes unable to pay its debt, service interest charges or otherwise commits an event of default under the Credit Agreement, the lenders under the Fourth Amended and Restated Credit Agreement may foreclose on or sell the Company's assets.

³ See "Non-GAAP measures".

The Company may incur substantially more indebtedness, which could exacerbate the risks that the Company faces.

The Company may incur substantial additional indebtedness in the future. The terms of the Fourth Amended and Restated Credit Agreement restrict, but do not completely prohibit, the Company from doing so. If new debt or other liabilities are added to the Company's current debt levels, the related risks that the Company face could intensify.

Restrictive covenants in the Fourth Amended and Restated Credit Agreement, and in future debt instruments may restrict the Company's ability to pursue its business strategies.

The Fourth Amended and Restated Credit Agreement limit, and the terms of any future indebtedness may limit, the Company's ability, among other things, to:

- incur or guarantee additional indebtedness;
- make certain investments;
- declare or pay dividends or make distributions on its shares;
- prepay subordinated indebtedness;
- sell assets, including shares of any future restricted subsidiaries;
- agree to payment restrictions affecting any future restricted subsidiaries;
- consolidate, merge, sell or otherwise dispose of all or substantially all of its assets;
- enter into transactions with its affiliates;
- incur liens;
- engage in business other than the oil and gas business; and
- designate certain of its future subsidiaries as unrestricted subsidiaries.

The restrictions contained in these agreements could limit the Company's ability to plan for, or react to, market conditions, meet capital needs, make acquisitions or otherwise restrict the Company's activities or business plans.

Statement of Reserves Data and Other Oil and Natural Gas Information

The determination of tight oil, NGLs, and shale gas reserves involve the preparation of estimates that have an inherent degree of associated risk and uncertainty. The estimation and classification of reserves is a complex process involving the application of professional judgment combined with geological and engineering knowledge to assess whether specific classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. In addition, rules set forth in the COGE Handbook and NI 51-101 override professional judgments as to volumes of recovery, well productivity and other factors.

NI 51-101 defines "shale gas" as natural gas (i) contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay minerals, and (ii) that usually requires the use of hydraulic fracturing to achieve economic production rates. The Company has also categorized what is typically referred to as "tight gas" under "shale gas" since "tight gas" is not defined in NI 51-101. This includes natural gas that is contained in low-permeability shales, siltstones and carbonates, in which the natural gas is primarily contained in microscopic pore spaces that are poorly connected to one another, which typically requires the use of hydraulic fracturing to achieve economic production rates.

Unless otherwise specified, the NGLs reported by McDaniel, the Company's independent qualified reserves evaluator, that are referred to in this AIF are reported on a combined basis with any condensate as required under NI 51-101.

The information set forth in this AIF relating to Pipestone Energy's reserves and future net revenues constitutes forward-looking statements which are subject to certain risks and uncertainties. See "*Forward-Looking Statements*" and "*Risk Factors*".

Reserves Disclosure

Reserves are classified as proved reserves, probable reserves or possible reserves according to the certainty associated with the estimates. Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories. For definitions of each of these reserve categories and certain related terminology that is used in this AIF, see "*Selected Terms*". Additional clarification of the classification of reserves, the certainty levels associated with reserves estimates and the effect of aggregation are provided in the COGE Handbook.

The qualitative certainty levels referred to in the definitions of proved reserves, probable reserves, possible reserves, developed reserves, developed non-producing reserves, developed producing reserves and undeveloped reserves (as such terms are defined under "*Selected Terms*") are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

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

In its evaluation of the Company's reserves, as at December 31, 2022, McDaniel attributed reserves to properties in the middle and lower intervals of the Montney formation across the Pipestone Project area.

Statement of Reserves Data

Statement of Reserves Data and Other Oil and Natural Gas Information

Set forth below is a summary of Pipestone Energy's tight oil, NGLs, and shale gas reserves, as evaluated in the McDaniel Reserves Report as at December 31, 2022. The Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in respect of the McDaniel Reserves Report and the Report of Management and Directors on Oil and Gas Disclosure for the McDaniel Reserves Report are attached as Appendices "A" and "B" to this AIF, respectively.

Disclosure of Reserves Data

The reserves data set forth in this AIF are based upon the McDaniel Reserves Report prepared in accordance with NI 51-101. The McDaniel Reserves Report, from which the data set forth below are derived, is dated February 13, 2023 and evaluated Pipestone Energy's reserves as of December 31, 2022. The reserves data summarizes the tight oil, NGLs, and shale gas reserves of Pipestone Energy and the net present values of future net revenue for the reserves using forecast prices and costs, not including the impact of any risk management activities. Reserves have been booked in the Montney "B", "C" and "D" intervals of the Middle Montney formation, with six wells in the Lower Montney. The McDaniel Reserves Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and CSA 51-324. Pipestone Energy engaged McDaniel to provide an evaluation of its proved and proved plus probable reserves. All of Pipestone Energy'

reserves are in the Province of Alberta.

The present value of future net revenue before and after income taxes has been estimated by McDaniel. The estimates of the after-income tax value of future net revenue have been prepared based on before income tax reserves information and includes assumptions and estimates of Pipestone Energy's tax pools provided by management of the Company 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 Pipestone Energy's 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 Pipestone Energy as a business entity, which may be significantly different.

All evaluations of future net revenue contained in the McDaniel Reserves Report are after the deduction of royalties, development costs, production costs and Abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. 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. There is no assurance that the forecast price and cost assumptions contained in the McDaniel Reserves Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized herein. Readers should review the relevant definitions and information that is contained in "*Selected Terms*" in conjunction with the following tables and notes. The recovery and reserves estimates described herein are estimates only. The actual reserves associated with Pipestone Energy's properties may be greater or less than those calculated. See "*Risk Factors*".

The historical production information used by McDaniel came from the Company. The Company also provided McDaniel with other required information, such as operating statements, land data, logs from recently drilled wells and field development plans. McDaniel incorporated all this data into its analysis in accordance with standards set out in the COGE Handbook. The standards in the COGE Handbook require McDaniel to plan and perform an assessment of the Company's reserves data in order to obtain reasonable assurance as to whether such reserves data are free of material misstatement.

McDaniel Reserves Report

The tables below summarize the data contained in the McDaniel Reserves Report and, as a result, may contain slightly different numbers than such report due to rounding. Due to rounding, certain columns may not add exactly. Except as otherwise indicated, net present values and future net revenues are based on McDaniel's forecast prices, as set forth below.

Summary of Reserves

SUMMARY OF RESERVES AS OF DECEMBER 31, 2022						
RESERVES CATEGORY	LIGHT & MEDIUM OIL		HEAVY OIL		TIGHT OIL	
	Gross ⁽¹⁾ (Mbbl)	Net ⁽²⁾ (Mbbl)	Gross ⁽¹⁾ (Mbbl)	Net ⁽²⁾ (Mbbl)	Gross ⁽¹⁾ (Mbbl)	Net ⁽²⁾ (Mbbl)
Developed Producing	-	-	-	-	25	22
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-
TOTAL PROVED	-	-	-	-	25	22
TOTAL PROBABLE	-	-	-	-	6	5
TOTAL PROVED + PROBABLE	-	-	-	-	32	27

	CONVENTIONAL NATURAL GAS		SHALE GAS		NATURAL GAS LIQUIDS ⁽³⁾	
RESERVES CATEGORY	Gross ⁽¹⁾ (MMcf)	Net ⁽²⁾ (MMcf)	Gross ⁽¹⁾ (MMcf)	Net ⁽²⁾ (MMcf)	Gross ⁽¹⁾ (Mbbbl)	Net ⁽²⁾ (Mbbbl)
Developed Producing	-	-	191,143	167,886	21,460	16,274
Developed Non-Producing	-	-	3,297	3,053	412	373
Undeveloped	-	-	366,315	323,251	44,572	35,862
TOTAL PROVED	-	-	560,755	494,190	66,443	52,509
TOTAL PROBABLE	-	-	246,512	208,000	29,277	21,207
TOTAL PROVED + PROBABLE	-	-	807,267	702,190	95,721	73,716

(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.

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) AS OF DECEMBER 31, 2022 AT FORECAST PRICES AND COSTS

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)					AFTER INCOME TAXES DISCOUNTED AT (%/YEAR)				
	0.0% (M\$)	5.0% (M\$)	10.0% (M\$)	15.0% (M\$)	20.0% (M\$)	0.0% (M\$)	5.0% (M\$)	10.0% (M\$)	15.0% (M\$)	20.0% (M\$)
Developed Producing	928,790	796,305	694,959	619,393	561,900	821,055	710,452	623,487	557,912	507,693
Developed Non-Producing	21,602	19,342	17,592	16,194	15,050	16,633	14,881	13,523	12,439	11,552
Undeveloped	1,378,198	964,746	696,087	514,309	386,573	1,055,790	718,160	499,033	351,672	249,033
TOTAL PROVED	2,328,589	1,780,393	1,408,638	1,149,896	963,524	1,893,478	1,443,493	1,136,043	922,023	768,277
TOTAL PROBABLE	1,271,061	830,638	585,251	438,241	343,982	975,090	634,918	444,979	331,650	259,404
TOTAL PROVED + PROBABLE	3,599,651	2,611,031	1,993,889	1,588,137	1,307,506	2,868,568	2,078,411	1,581,022	1,253,673	1,027,681

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2022 FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ⁽¹⁾ (M\$)	ROYALTIES ⁽²⁾ (M\$)	OP. COSTS (M\$)	DEV. COSTS (M\$)	ABAND. & REC. COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Total Proved	7,811,773	1,268,546	2,925,330	1,233,866	55,442	2,328,589	435,111	1,893,478
Total Proved + Probable	11,600,986	2,092,139	4,367,737	1,477,399	64,061	3,599,651	731,082	2,868,568

(1) Includes all product revenues and other revenues as forecast.

(2) Royalties include any net profits interests paid.

FUTURE NET REVENUE BY PRODUCTION GROUP AS OF DECEMBER 31, 2022 FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (Discounted @ 10%) (M\$)	UNIT VALUE ⁽¹⁾ \$/bbl \$/Mcf
Total Proved	Tight Oil (Including Solution Gas and By-products)	592	26.71
	Shale Gas (Including By-products)	1,408,046	2.85
	Total	1,408,637	
Total Proved + Probable	Tight Oil (Including Solution Gas and By-products)	732	26.89
	Shale Gas (Including By-products)	1,993,157	2.84
	Total	1,993,889	

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

Pricing Assumptions

The forecast of prices, inflation and exchange rates provided in the table below were computed using the average forecasts that were prepared by McDaniel, GLJ Petroleum Consultants Ltd. and Sproule Associates Ltd., effective January 1, 2023. Each of these evaluator's forecasts are available on their respective websites at www.mcdan.com, www.gljpc.com and www.sproule.com. The average of the three evaluator's forecasts were utilized in the McDaniel Reserves Report and the summary of McDaniel's evaluation that is reflected herein.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS AS OF JANUARY 1, 2023 FORECAST PRICES AND COSTS

3C PRICE FORECAST	WTI CRUDE OIL (US\$/bbl)		EDMONTON CONDENSATE (\$/bbl)		HENRY HUB NATURAL GAS (US\$/MMBtu)		AECO NATURAL GAS (Cdn\$/MMBtu)	
	2023	2022	2023	2022	2023	2022	2023	2022
2023	\$80.33	\$68.78	\$106.22	\$85.53	\$4.74	\$3.44	\$4.23	\$3.21
2024	\$78.50	\$66.76	\$101.35	\$82.98	\$4.50	\$3.17	\$4.40	\$3.05
2025	\$76.95	\$68.09	\$98.94	\$84.63	\$4.31	\$3.24	\$4.21	\$3.11
2026	\$77.61	\$69.45	\$100.19	\$86.33	\$4.40	\$3.30	\$4.27	\$3.17
2027	\$79.16	\$70.84	\$101.74	\$88.05	\$4.49	\$3.37	\$4.34	\$3.23
2028	\$80.74	\$72.26	\$103.78	\$89.82	\$4.58	\$3.44	\$4.43	\$3.30
2029	\$82.36	\$73.70	\$105.85	\$91.61	\$4.67	\$3.50	\$4.51	\$3.36
2030	\$84.00	\$75.18	\$107.97	\$93.44	\$4.76	\$3.58	\$4.60	\$3.43
2031	\$85.69	\$76.68	\$110.13	\$95.32	\$4.86	\$3.65	\$4.69	\$3.50
2032	\$87.40	\$78.21	\$112.33	\$97.22	\$4.95	\$3.72	\$4.79	\$3.57
Thereafter	+2%/Yr	+2%/Yr	+2%/Yr	+2%/Yr	+2%/Yr	+2%/Yr	+2%/Yr	+2%/Yr

3C PRICE FORECAST	EDMONTON ETHANE (\$/bbl)		EDMONTON PROPANE (\$/bbl)		EDMONTON BUTANES (\$/bbl)		FOREIGN EXCHANGE (US\$/Cdn\$)		INFLATION RATE (%)	
	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022
2023	\$13.75	\$10.33	\$39.80	\$35.92	\$53.88	\$50.17	\$0.745	\$0.797	0.0	2.3
2024	\$14.33	\$9.81	\$39.14	\$34.62	\$52.67	\$48.53	\$0.765	\$0.797	2.3	2.0
2025	\$13.77	\$10.01	\$39.74	\$35.31	\$51.42	\$49.50	\$0.768	\$0.797	2.0	2.0
2026	\$13.98	\$10.22	\$39.86	\$36.02	\$51.61	\$50.49	\$0.772	\$0.797	2.0	2.0
2027	\$14.20	\$10.42	\$40.47	\$36.74	\$52.39	\$51.50	\$0.775	\$0.797	2.0	2.0
2028	\$14.49	\$10.64	\$41.28	\$37.47	\$53.44	\$52.53	\$0.775	\$0.797	2.0	2.0
2029	\$14.79	\$10.86	\$42.11	\$38.22	\$54.51	\$53.58	\$0.775	\$0.797	2.0	2.0
2030	\$15.09	\$11.08	\$42.95	\$38.99	\$55.60	\$54.65	\$0.775	\$0.797	2.0	2.0
2031	\$15.39	\$11.31	\$43.81	\$39.77	\$56.71	\$55.74	\$0.775	\$0.797	2.0	2.0
2032	\$15.71	\$11.54	\$44.47	\$40.56	\$57.56	\$56.86	\$0.775	\$0.797	2.0	2.0
Thereafter	+2%/Yr	+2%/Yr	+2%/Yr	+2%/Yr	+2%/Yr	+2%/Yr	\$ 0.797	\$ 0.763	2.0	2.0

Weighted-average historical prices realized (before hedging) by Pipestone Energy for the period from January 1, 2022 to December 31, 2022, were \$118.15/bbl for condensate, \$53.81/bbl for other NGLs (excluding condensate) and \$6.60/Mcf for natural gas that is primarily subject to AECO 5A pricing with a portion of sales exposed to Chicago Citygate pricing. The Company had immaterial tight oil production in 2022. Of the Company's total petroleum and natural gas sales in 2022, condensate and oil sales represented 53% of the Company's revenue (with oil accounting for less than 1% of revenue), natural gas sales represented 36% of the Company's revenue and other NGLs sales represented 11% of the Company's revenues.

Reserves Reconciliation

	TIGHT OIL (Mbbbl)	NATURAL GAS (MMcf)	NATURAL GAS LIQUIDS ⁽¹⁾ (Mbbbl)	COMPANY TOTAL (Mboe)
Company Gross				
Proved Developed Producing				
Balance - December 31, 2021	22.7	145,910	16,169	40,510
Extensions	-	1,478	328	574
Economic Factors	10.5	11,325	1,126	3,024
Technical Revisions	26.0	(3,483)	(161)	(716)
Technical Revisions – PUD Transfer	-	75,910	8,646	21,298
Production	(33.9)	(39,997)	(4,648)	(11,348)
Balance - December 31, 2022⁽²⁾	25.3	191,143	21,460	53,343
Total Proved				
Balance - December 31, 2021	22.7	553,877	67,813	160,148
Extensions	-	129,578	18,302	39,899
Economic Factors	10.5	19,490	2,075	5,334
Technical Revisions	26.0	(78,760)	(13,052)	(26,153)
Technical Revisions – PUD Transfer	-	(23,434)	(4,047)	(7,953)
Production	(33.9)	(39,997)	(4,648)	(11,348)
Balance - December 31, 2022⁽²⁾	25.3	560,755	66,443	159,928

Total Probable				
Balance - December 31, 2021	6.9	403,757	47,775	115,075
Extensions	-	(28,101)	(2,138)	(6,821)
Economic Factors	35.6	14,425	1,569	4,008
Technical Revisions	(36.0)	(133,395)	(16,349)	(38,618)
Technical Revisions – PUD Transfer	-	(10,174)	(1,580)	(3,275)
Production	-	-	-	-
Balance - December 31, 2022 ⁽²⁾	6.5	246,512	29,277	70,369
Proved + Probable				
Balance - December 31, 2021	29.5	957,632	115,588	275,223
Extensions	-	101,477	16,165	33,077
Economic Factors	46.1	33,916	3,644	9,342
Technical Revisions	(10.0)	(212,156)	(29,401)	(64,770)
Technical Revisions – PUD Transfer	-	(33,608)	(5,627)	(11,228)
Production	(33.9)	(39,997)	(4,648)	(11,348)
Balance - December 31, 2022 ⁽²⁾	31.7	807,267	95,721	230,297

(1) Natural Gas Liquids includes condensate volumes. Booked 2P condensate volumes (including pentanes plus) are 66,584 Mbbls as of December 31, 2022.

(2) Amounts may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty to be recoverable where significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. Probable undeveloped reserves are those additional reserves that are less certain to be recovered than proved reserves where significant expenditure is required to render them capable of production. The McDaniel Reserves Report contains proved and probable undeveloped reserves that have been estimated in accordance with the procedures and standards contained in the COGE Handbook.

Pipestone Energy plans to spend a significant portion of its drilling and completions capital over the next five years to develop its proved undeveloped reserves. All of the Company's proved undeveloped reserves locations are located within the Pipestone Area and are in close proximity to existing and planned infrastructure. Pipestone Energy's booked proved undeveloped reserves locations are all in the Montney and offset existing producing wells, such that the Company has a higher degree of confidence in the production profile from these undeveloped locations than other Montney drilling locations on its lands. The Company's proved undeveloped reserves locations underpin its near-term gathering, processing and transportation commitments and the Company believes that these locations will be the primary driver of production and cash flow over the next five years.

As of December 31, 2022, undeveloped reserves represented approximately 66% of total gross proved reserves and approximately 70% of gross proved plus probable reserves, all of which are located in the Pipestone Project area. All proved undeveloped reserves are planned to be developed in the next five years, with the majority of the related capital spending to occur within the next four years. All probable undeveloped reserves are planned to be developed in the next seven years, with the majority of related capital spending to occur within the next six years.

The pace of development of these reserves is influenced by several factors including, but not limited to, the outcomes of drilling and reservoir evaluations, changes in commodity pricing, changes in capital allocations, changing technical conditions, access to markets, regulatory changes and impact of future acquisitions and dispositions. These reserves are reviewed, and development plans are revised accordingly as new information becomes available.

Proved Undeveloped Reserves

	Tight Oil (Mbbbl)		Shale Gas (MMcf)		NGLs (Mbbbl)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
December 31 st , 2020	-	-	48,655	341,324	4,632	44,096
December 31 st , 2021	-	-	106,178	391,595	13,311	49,979
December 31 st , 2022	-	-	128,100	366,315	17,974	44,572

Probable Undeveloped Reserves

	Tight Oil (Mbbbl)		Shale Gas (MMcf)		NGLs (Mbbbl)	
Year	First Attributed	Cumulative at Year End	First Attributed ⁽¹⁾	Cumulative at Year End	First Attributed ⁽¹⁾	Cumulative at Year End
December 31 st , 2020	-	-	21,437	297,358	3,249	35,438
December 31 st , 2021	-	-	60,324	344,520	6,486	41,491
December 31 st , 2022	-	-	70,962	191,686	9,399	23,080

(1) The Probable Undeveloped First Attributed volume is the first true Probable only extension accounting for new Undeveloped Probable only reserves.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgment and decision-making on the basis of the available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on production expectations, prices and economic conditions as at December 31, 2022. Factors and assumptions that affect these reserves estimates include, among other things: (a) historical production in the area compared with production rates from analogous producing areas; (b) initial production rates; (c) production decline rates; (d) ultimate recovery of reserves; (e) success of future development activities; (f) marketability of production; (g) effects of government regulations; and (h) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserves estimates may 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 and reservoir performance, geological conditions, production, prices, changes in Company strategy, economic conditions and governmental restrictions. These revisions can be either positive or negative.

In connection with its operations, the Company will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. The Company budgets for and recognizes a liability based on the estimated present value of the future decommissioning liabilities associated with its oil and gas assets. See Note 10 of the Company's audited consolidated financial statements for the years ended December 31, 2022. There are no unusually significant abandonment and reclamation costs associated with the Company's reserves properties or to properties with no attributed reserves.

The evaluated oil and gas properties of the Company have no material extraordinary risks or uncertainties beyond those that are inherent in unconventional oil and gas exploration and production operations. See "Risk Factors".

Future Development Costs

The following table sets forth development costs deducted in the estimate of Pipestone Energy's future net revenue attributable to the reserves categories noted below.

Year	Total Proved (C\$MM)	Total Proved + Probable (C\$MM)
2023	\$243	\$243
2024	\$287	\$287
2025	\$279	\$279
2026	\$257	\$257
2027	\$138	\$172
Remainder Thereafter	\$30	\$240
Total FDC Undiscounted	\$1,234	\$1,477
Total FDC Discounted (10%)	\$997	\$1,132

Pipestone Energy expects to fund the development costs of its reserves through future adjusted funds flow from operations and borrowings under its current Reserve-Based Loan to the extent necessary. There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all of the reserves attributed in the McDaniel Reserves Report. Failure to develop those reserves could have a negative impact on Pipestone Energy's future net revenue relative to the estimates provided herein.

Interest or other costs of external funding are not included in Pipestone Energy's reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. Pipestone Energy does not anticipate that interest or other funding costs would make development of any of its properties uneconomic.

The future development costs set forth above do not include costs associated with abandonment and reclamation obligations.

Below is the expected Abandonment, Decommissioning and Reclamation Cost forecast for Pipestone Energy:

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038+	Total
Abandonment and Reclamation																	
Cost Forecast (M\$)																	
Total Proved																	
Undiscounted	1,121	73	528	-	-	177	-	-	73	-	-	-	-	-	146	53,325	55,442
Discounted @ 10%	1,116	66	435	-	-	109	-	-	34	-	-	-	-	-	38	3,847	5,646
Total Proved + Probable																	
Undiscounted	1,121	73	528	-	-	177	-	-	73	-	-	-	-	-	146	61,944	64,061
Discounted @ 10%	1,116	66	435	-	-	109	-	-	34	-	-	-	-	-	38	3,420	5,218

Other Oil and Natural Gas Information

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which Pipestone Energy had a working interest as at December

	OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta, Canada	1	0.2	7	4.5	95	90.8	29	25.5
TOTAL	1	0.2	7	4.5	95	90.8	29	25.5

31, 2022, all of which are located in Alberta.

Properties with No Attributed Reserves

The properties in which Pipestone Energy has an interest to which, generally, no reserves have been attributed, as at December 31, 2022, all of which are located in Alberta, are shown as "Undeveloped Acres" in the table that is provided below.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta, Canada	39,842	31,324	83,682	75,737	123,524	107,061
TOTAL	39,842	31,324	83,682	75,737	123,524	107,061

The Company continually reviews the economic viability and ranking of these unproved properties on the basis of product pricing, capital availability, the anticipated cost to re-acquire, and the allocation and level of infrastructure development in any specific area. From this process, some properties are scheduled for economic development activities while others are temporarily held inactive, sold, swapped or allowed to expire. There is no guarantee that commercial reserves will be discovered or developed on these properties. Of the Company's land holdings, the Company holds approximately 90,029 net acres of Montney rights. There are 18,721 acres of land holdings that are scheduled to expire by December 31, 2022 however the majority are expected to be continued. The Company closely monitors land expiries within our core area and plan our development program with the strategy of minimizing expiries of undeveloped lands.

When determining gross and net acreage, where Pipestone Energy holds two or more leases granting stratigraphic interests which overlap geographically, the acreage is reported for each lease; where Pipestone Energy holds two or more stratigraphic interests in a single lease that overlap geographically, the acreage is reported only once.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

There are several economic factors and significant uncertainties that affect Pipestone Energy's anticipated development of its properties to which no reserves are attributed. Pipestone Energy will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil, natural gas and NGLs from these properties in the future. If cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Company. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations on such properties. The inability of Pipestone Energy to access sufficient capital for its exploration and development purposes could have a material adverse effect on the Company's ability to execute its business strategy to develop these prospects. See "Risk Factors". The primary economic factors that affect the development of the properties to which no reserves have been attributed are future commodity prices for oil, natural gas and NGLs (and the Company's outlook relating to such prices) and the future costs of drilling, completing, tying-in and operating wells at the time

that such activities are considered. The primary uncertainties that affect the development of such lands are the future drilling and completion results achieved in the development activities, drilling and completion results achieved by others on lands in close proximity to these lands, and 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. Conversely, uncertainty as to the timing and nature of the evolution or development of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such properties.

Forward Contracts

The Company's operations expose it to fluctuations in commodity prices. Commodity prices for liquids and natural gas are affected by both global economic events and North American specific factors that influence supply and demand. Pipestone Energy's management continuously monitors commodity prices. Pipestone Energy uses risk management contracts in order to reduce its exposure to fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. A summary of the contracts in which the Company has fixed the price of future production, outstanding at and subsequent to December 31, 2022, have been disclosed in Note 4 of the audited consolidated financial statements of the Company for the year ended December 31, 2022, which are available on the SEDAR website at www.sedar.com.

Pipestone Energy's commodity price risk management program is designed to reduce cash flow volatility, enhance certainty on funding available for the Company's capital expenditure program and service debt. Mitigation of cash flow volatility is an integral component of the Company's business strategy. Business conditions are monitored regularly and reviewed with the Board of Directors to establish risk management guidelines, such as target prices and volumes, which are then used by management in carrying out the Company's strategic risk management program while also meeting minimum hedging requirements, if any, imposed by the Company's external lenders. See *"Risk Factors – The Company has entered into commodity price hedging instruments and may in the future enter into additional contracts for a portion of its production, which may result in the Company making cash payments or prevent the Company from receiving the full benefit of increases in prices for oil, condensate and natural gas"*.

At December 31, 2022, Pipestone Energy had the following weighted-average commodity risk management contracts in place:

Term	C\$ WTI swaps		AECO 5A swaps	
	bbls/d	C\$/bbl	GJ/d	C\$/GJ
Jan. – Mar. '23	750	122.18	20,000	7.22
Apr. – Jun. '23	-	-	6,595	3.98
Jul. – Sept. '23	-	-	6,595	3.98
Oct. – Dec. '23	-	-	2,200	3.98

Processing and Transportation Obligations

As part of normal business operations, Pipestone Energy enters into long-term commitments to gather, compress, process and transport (as applicable) its oil, natural gas, condensate and other NGLs production volumes. Additional information related to the Company's gathering, processing and transportation commitments have been disclosed in Note 19 of the audited financial statements of the Company for the year ended December 31, 2022, which are available on the SEDAR website at www.sedar.com.

Tax Horizon

During 2022, Pipestone Energy did not pay any income related taxes and it expects that based on its current tax pools available, current tax legislation enacted and commodity price forecasts per its reserves, that income taxes will become payable in 2023 on its total proved reserves and in 2023 on its total proved plus probable reserves. The actual cash outflow associated with the

accrued taxes that become payable in 2023 does not occur until early 2024. See *"Risk Factors – Reassessment of the Company's prior transactions and tax filings could subject the Company to higher than expected past or future tax liability, interest or penalties. Changes to tax laws, or the interpretation thereof, may have a detrimental effect on the Company"*.

Costs Incurred

The following table summarizes the gross capital expenditures made by Pipestone Energy on oil and natural gas properties for the year ended December 31, 2022:

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
	(M\$)	(M\$)	(M\$)	(M\$)
Pipestone	-	96	134	245,197

Exploration & Development Activities

The following table sets forth the gross and net wells in which the Company participated during the year ended December 31, 2022:

	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Natural Gas	28.0	26.5	-	-	28.0	26.5
Oil	-	-	-	-	-	-
Service	1.0	1.0	-	-	1.0	1.0
Stratigraphic Test	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	29.0	27.5	-	-	29.0	27.5

Production Estimates

The following table sets out for each product type the gross volume of production estimated for the year ending December 31, 2023 in the estimates contained in the McDaniel Reserves Report for gross proved reserves and gross probable reserves:

Production Estimate – Year Ending December 31, 2023				
	Shale Gas	NGLs	Tight Oil	Total
Reserve Category	(MMcf)	(Mbbbl)	(Mbbbl)	(Mboe)
Proved	49,108	5,874	8	14,067
Probable	2,647	435	1	876
Total Proved plus Probable	51,755	6,309	8	14,943

All of the Company's production is from the Pipestone Project and all of the Company's production estimated for the year ended December 31, 2023 is expected to come from the Pipestone Project. Actual results may differ significantly from the information below. See *"Forward-Looking Statements"* and *"Risk Factors"* and in particular *"Risk Factors - Estimates of oil, NGLs and natural gas reserves and production therefrom are uncertain and may vary substantially from actual production"*.

Production History

The following table sets forth certain information in respect of production volumes, product prices received, royalties paid, production costs incurred and netbacks received by Pipestone Energy for each quarter of its most recently completed financial period:

	December 31, 2022 Year End			
	1 st Quarter	2 nd Quarter	3 rd Quarter	4 th Quarter
Production				
Tight oil (bbls/d)	33	79	41	218
Condensate (bbls/d)	7,963	8,428	8,893	9,833
Other natural gas liquids (bbls/d)	3,861	4,137	3,766	4,027
Natural gas (Mcf/d)	94,346	108,754	116,455	118,428
Total production (boe/d)	27,581	30,770	32,109	33,816
Revenue				
Tight oil (\$/bbl)	104.71	128.74	108.64	98.99
Condensate (\$/bbl)	121.38	133.44	110.99	109.11
Other natural gas liquids (\$/bbl)	55.47	61.18	51.94	46.53
Natural gas (\$/Mcf)	5.53	8.50	6.09	6.19
Total revenue (\$/boe)	61.85	75.13	59.05	59.59
Realized loss on commodity risk management contracts (\$/boe)	4.94	10.51	2.52	0.89
Royalties (\$/boe)	4.21	5.96	7.75	7.74
Operating expenses (\$/boe)	11.02	12.88	13.48	12.87
Transportation (\$/boe)	3.99	3.81	3.42	3.51
Operating netback⁽¹⁾ (\$/boe)	37.69	41.97	31.88	34.58

(1) See "Non-GAAP measures".

Description of Capital Structure

Reserve-Based Loan

Pipestone Energy is currently party to the Fourth Amended and Restated Credit Agreement with a syndicate of lenders which, as at the date hereof, provides for a \$250 million Senior Facility and a \$30 million Operating Line, which collectively comprise the \$280 million RBL. The revolving period of the RBL currently ends on May 29, 2023 with an additional one-year term out period thereafter if the revolving period is not extended. An extension of the revolving period is subject to majority lender consent.

At December 31, 2022, the Company had \$104.0 million drawn against the Senior Facility and \$1.5 million drawn on the Operating Line, for an aggregate draw on the RBL of \$105.5 million.

The borrowing base on the facility is scheduled to be redetermined in May 2023 and, subject to any further amendments, is based on the lenders' assessment of the Company's reserves and future commodity prices. If not extended by any or all lenders, the commitments of such non-extending lenders under the RBL will cease to revolve, all outstanding advances thereunder owing to such non-extending lenders will become repayable in one year from the term date and the margins owing on such outstanding advances will increase by 0.50%. In the event the borrowing base is reduced below amounts outstanding, any excess will become due and payable 60 days subsequently. See "*Risk Factors - Variations in foreign exchange rates and interest rates could negatively impact the Company's production revenues, the value of the Company's reserves and the Company's cost of debt*".

The Company is in compliance with all material terms of the Fourth Amended and Restated Credit Agreement and no lender has waived or been requested to waive any material breach by us of such agreement since its execution. Neither our financial position nor the value of the security under the Fourth Amended and Restated Credit Agreement has changed substantially and adversely since the initial indebtedness under the RBL was incurred.

Advances under the RBL are available by way of Canadian prime rate and U.S. base rate loans with interest rates ranging between 1.75% and 5.75% on the Senior Facility and Operating Line, over the bank's prime lending rate, as well as bankers' acceptances, which are subject to stamping fees and margins ranging from 2.75% to 6.75% on the Senior Facility and Operating Line. The

applicable interest rate varies, depending upon the Company's senior debt to EBITDA⁴ ratio calculated at the Company's previous quarter end for the last twelve months.

As at December 31, 2022, Pipestone Energy's applicable pricing included a 1.8% per annum margin on prime loans, a 2.8% per annum stamping fee and margin on bankers' acceptances along with a 0.7% per annum standby fee on the portion of the RBL that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal. For the year ended December 31, 2022 borrowing costs averaged 6.1%.

The Fourth Amended and Restated Credit Agreement contains customary borrowing base provisions and negative covenants including, but not limited to, restrictions on the Company's ability to incur indebtedness, grant liens or security interests on assets, sell or otherwise transfer assets, make distributions, make investments or provide financial assistance and the Company's ability to merge and consolidate with other companies or change the Company's line of business, in each case, subject to certain exceptions. The Company is permitted to purchase shares under its Normal Course Issuer Bid ("NCIB") provided that (i) the aggregate amount of all such purchases made between any two scheduled borrowing base dates does not exceed \$30.0 million and (ii) upon such purchases being made, the net debt to EBITDA⁴ ratio of the Company (calculated on a pro forma basis, taking into account such purchases) would be less than 1.50:1.00. The Company is also permitted to make other permitted distributions (including dividends and other share repurchases), provided that upon such other distribution being made, the net debt to EBITDA ratio of the Company (calculated on a pro forma basis) would be less than 1.50:1.00, (i) the aggregate principal amount outstanding under the credit facilities, on a pro forma basis after giving effect to such other distribution, does not exceed 80% of the commitment amount and (ii) not less than 20% of the Company's average daily forecasted production of crude oil, condensate and natural gas (determined on a combined basis, and net of royalties) is hedged and subject to commodity swap contracts for the immediately following twelve month period. Collectively, the purchases under the NCIB and other permitted distributions cannot exceed \$100.0 million between scheduled borrowing base dates.

The Fourth Amended and Restated Credit Agreement contains customary positive covenants including, but not limited to, delivery of financial and other information to the lenders, maintenance of existence, payment of taxes and other claims, maintenance of properties and insurance, access to books and records by the lenders, compliance with applicable laws and regulations, including environmental laws, and further assurances and provision of additional collateral and guarantees.

The Fourth Amended and Restated Credit Agreement provides that, upon the occurrence of certain events of default, the Company's obligations thereunder may be accelerated and the lending commitments terminated. Such events of default include payment defaults to the lenders, covenant defaults, inaccuracies of representations and warranties, bankruptcy and insolvency proceedings, business suspension, material money judgments, cross defaults, change of control and other customary events of default. As is customary, the facility contains material adverse change clauses which would enable the lenders to demand immediate repayment of amounts outstanding if determined to represent an event of default.

The indebtedness under the Fourth Amended and Restated Credit Agreement is secured by floating charges and a security interest against the Company's current and future real and personal property. The Company does not currently have any material subsidiaries and, as such, no guarantees have been provided under the Fourth Amended and Restated Credit Agreement. A copy of the Fourth Amended and Restated Credit Agreement has been filed under Pipestone Energy's profile on the SEDAR website at www.sedar.com

Letter of Credit Facility

Pipestone Energy has a \$22.5 million EDC Letter of Credit Facility under Export Development Canada's performance security guarantee program. At December 31, 2022, the Company had \$13.7 million of letters of credit issued and outstanding against the EDC Letter of Credit Facility (December 31, 2021 - \$12.3 million). Letters of credit issued under the EDC Letter of Credit Facility do not impact Pipestone Energy's borrowing capacity under the RBL, and as such provides the Company with additional liquidity.

⁴ See "Non-GAAP measures".

Share Capital

The authorized share capital of the Company as of the date hereof consists of an unlimited number of Common Shares and an unlimited number of Convertible Preferred Shares. As of December 31, 2022, there were 278,948,774 Common Shares issued and outstanding and nil Convertible Preferred Shares issued and outstanding.

Common Shares

Holders of Common Shares are entitled to receive notice of, to attend and to vote at all meetings of shareholders and are entitled to one vote per Common Share held at such meetings. In the event of any voluntary or involuntary liquidation, dissolution or winding-up of Pipestone Energy or any other distribution of Pipestone Energy's assets among its shareholders for the purpose of winding-up its affairs, holders of Common Shares are entitled to share equally, share for share, in the remaining property of the Company.

Convertible Preferred Shares

On September 15, 2020, Pipestone Energy issued 70,000 Convertible Preferred Shares at a price of \$970 per share for gross proceeds of \$67.9 million. The Company incurred \$1.2 million of issuance costs related to the transaction for net proceeds received of \$66.7 million. The Convertible Preferred Shares had a face value of \$1,000 per share for a cumulative \$70.0 million (issued at a 3.0% or \$2.1 million discount) and entitled the holders to an annual dividend of 6.5% per year payable quarterly in-kind, or in cash after two years from issuance, at the sole option of Pipestone Energy. Dividends paid in-kind accrued and compounded on a quarterly basis using a twelve-month calendar consisting of 30-day months. The Convertible Preferred Shares had a term of five years ending on September 15, 2025.

The face value of the Convertible Preferred Shares plus any accrued dividends paid in-kind at a point in time forms the Liquidation Preference of the Convertible Preferred Shares. The Liquidation Preference of the Convertible Preferred Shares was convertible into Common Shares at a price of \$0.85 per Common Share, subject to customary adjustments, at the discretion of the holders at any time. After two years, if, among other things, the closing price of the Common Shares was above \$1.70 for 20 days over a 30-day trading period and Pipestone Energy had an effective shelf prospectus covering resales of the underlying Common Shares to be received upon conversion of the Convertible Preferred Shares, the Convertible Preferred Shares would automatically convert into Common Shares at \$0.85 per Common Share. In the event that there were Convertible Preferred Shares outstanding at the end of the five-year term, the Liquidation Preference of the Convertible Preferred Shares would automatically convert into Common Shares at either \$0.85 per Common Share, if the Common Shares are trading at a price at or in excess of \$0.85 per Common Share, or otherwise at a price equal to 95% of the previous 20-day volume weighted average Common Share price.

On September 30, 2022, all of the holders of the Convertible Preferred Shares exercised their right to the voluntary early conversion of the outstanding Convertible Preferred Shares. As at September 30, 2022, the date of the conversion notices, the Convertible Preferred Shares had a liquidation preference, including accruals of the dividends paid in-kind on the Convertible Preferred Shares, of \$79,850,406, and were converted into an aggregate of 93,941,655 Common Shares on October 5, 2022. No dividends were declared or paid on the Convertible Preferred Shares while they were outstanding. Following the conversion of the Convertible Preferred Shares, Pipestone Energy had 279,442,517 Common Shares outstanding.

Normal Course Issuer Bid

On November 22, 2021, the Company implemented its inaugural NCIB through the facilities of the TSX. The inaugural NCIB was fully executed with the purchase and cancellation of 9,598,347 common shares of the Company at an average price of \$4.44 per share.

On November 23, 2022, the TSX approved the Company's notice to renew its NCIB to purchase, for cancellation, a maximum of 13,936,907 Common Shares, representing 5% of its issued and outstanding Common Shares as at November 14, 2022. Purchases of Common Shares under the renewed NCIB are expected to be made in open market transactions on the TSX and other alternative trading platforms in Canada over a 12-month period. Any Common Shares purchased under the NCIB will be cancelled.

The NCIB commenced on November 25, 2022 and is due to expire no later than November 24, 2023.

Under the TSX rules, not more than 156,214 Common Shares, representing 25% of the average daily trading volume of 624,856 Common Shares on the TSX calculated for the six month period ended October 31, 2022 and excluding 5,107,800 Common Shares that the Company repurchased pursuant to its inaugural NCIB during this period, can be purchased on the TSX on any single trading day under the NCIB, with the exception that Pipestone Energy may make one block purchase per calendar week in excess of the daily repurchase restrictions.

For the year ended December 31, 2022, the Company repurchased nil Common Shares under the renewed NCIB.

Dividends

On November 23, 2022, the Board established a quarterly dividend of \$0.030 per Common Share or \$0.12 per Common Share on an annualized basis, commencing in the first quarter of 2023.

The Board will review and determine the dividend rate periodically after considering expected commodity prices, foreign exchange rates, economic conditions, production volumes, taxes payable, and Pipestone Energy's capacity to fund operating and investing opportunities. The dividend rate is established with the intent of absorbing short-term market volatility over several months. It also recognizes the intention of maintaining a strong financial position to take advantage of business development opportunities and withstand periods of commodity price volatility.

Dividends will be paid quarterly to shareholders of record as of the close of business on the last business day of each quarter with the corresponding payment date being the 15th day (or next business day) of the following month. Dividend payments are not guaranteed and the amount of cash to be distributed as dividends in the future may change. Any decision to pay dividends will be determined at the discretion of the Board after reviewing the overall dividend policy of the Company and after consideration of numerous factors including: [(i) Pipestone Energy's earnings; (ii) financial requirements for Pipestone Energy's operations; (iii) the satisfaction by the Company of the liquidity and insolvency tests described in the ABCA; (iv) any agreements relating to Pipestone Energy's indebtedness that restrict the declaration and payment of dividends; (v) the amount of capital expenditures; and (vi) other conditions existing from time to time. The dividends paid on the Common Shares pursuant to the Company's dividend policy are designated as "eligible dividends" for Canadian income tax purposes, unless otherwise notified.

Market for Securities

Trading Price and Volume

The following table sets forth the price range and trading volume of the Common Shares as reported by the TSX for the periods indicated.

	Price Range		Average Daily Volume
	High (\$/share)	Low (\$/share)	
2022			
January	4.96	3.83	522,856
February	5.10	4.36	427,278
March	5.89	4.42	519,388
April	5.64	4.50	377,148
May	6.17	4.22	710,911
June	6.72	3.74	717,952
July	4.37	3.26	706,536
August	5.20	3.61	785,502
September	4.99	3.33	548,445
October	4.44	3.77	509,327
November	4.60	3.13	985,753
December	3.55	2.68	944,548
2023			
January	3.29	2.68	515,200
February	3.10	2.64	439,898
March (1 – 7)	3.06	2.86	283,340

Prior Sales

During the year ended December 31, 2022, Pipestone Energy issued a total of 593,486 stock options with a weighted-average exercise price of \$4.57, 591,850 restricted share units and 385,003 performance share units pursuant to the Pipestone Energy Corp. Long Term Incentive Plan. No funds are received by us until the stock options are exercised. On the payment date of the restricted share units and performance share units, the Company has the sole discretion as to whether the awards shall be paid in cash, Common Shares issued from treasury or Common Shares purchased on the TSX. See note 13 of our audited financial statements for the year ended December 31, 2022 for a summary of stock option, restricted share unit and performance share unit activity.

Escrowed Securities and Securities Subject to Contractual Restriction on Transfer

The following table summarizes Pipestone Energy's securities in escrow or subject to restrictions on transfer as of December 31, 2022:

Designation of Class	Number of Securities Held in Escrow or That are Subject to a Contractual Restriction on Transfer ⁽¹⁾	Percentage of Class ⁽²⁾
Common Shares	24,512,209	8.8%

Notes:

- (1) Odyssey Trust Company acts as depository for the Common Shares held in escrow. The escrow agreements provide for the release of the Common Shares held in escrow upon satisfaction by each of the shareholders of certain requirements under the *Income Tax Act* (Canada).
- (2) The percentage is based on 278,948,774 Common Shares being issued and outstanding as of December 31, 2022.

Directors and Officers

The names, municipalities of residence, any offices held with us, the period served as a director and principal occupations of our directors and officers are set out below:

Name & Municipality of Residence	Position	Director or Officer Since	Principal Occupation
Gordon Ritchie ⁽²⁾⁽³⁾⁽⁴⁾⁽¹⁰⁾ Calgary, Alberta	Chair and Director	January 2019	Former Vice Chairman of RBC Capital Markets.
Garth Braun ⁽³⁾⁽⁴⁾⁽⁵⁾⁽¹⁰⁾ Langley, British Columbia	Director	January 2019 ⁽⁵⁾	Founder and Director of Stage Completions Inc. and former Chairman, CEO and President of Blackbird.
William Lancaster ⁽³⁾⁽⁶⁾⁽⁷⁾⁽¹⁰⁾⁽¹¹⁾ Denver, Colorado	Director	January 2019	President of GMT Exploration.
John Rossall ⁽⁴⁾⁽⁸⁾⁽¹⁰⁾ Calgary, Alberta	Director	January 2019	Former Executive Director, North America for Repsol Oil & Gas Canada Inc. (formerly Talisman Energy Inc.)
Robert Tichio ⁽⁴⁾⁽¹⁰⁾⁽¹²⁾ New York, New York	Director	January 2019	Partner of Riverstone Holdings LLC
Jesal Shah ⁽⁷⁾⁽¹⁰⁾⁽¹²⁾ New York, New York	Director	June 2021	Managing Director of Riverstone Holdings LLC
Kimberly Anderson ⁽⁹⁾⁽¹⁰⁾ Calgary, Alberta	Director	September 2021	Chief Financial Officer of Heartland Generation
Paul Wanklyn Calgary, Alberta	President and CEO and a Director	January 2019	President and CEO of Pipestone Energy and previously Pipestone Oil Corp.
Dustin Hoffman Calgary, Alberta	Chief Operating Officer	September 2019	Chief Operating Officer since September 2019.

Name & Municipality of Residence	Position	Director or Officer Since	Principal Occupation
Craig Nieboer Calgary, Alberta	Chief Financial Officer	February 2019	Chief Financial Officer since February 2019.
Dan van Kessel Calgary, Alberta	Vice President, Corporate Development	January 2019	Vice President, Corporate Development since January 2019.
Alyson Goldman Calgary, Alberta	Corporate Secretary	February 2022	Partner at McCarthy Tétrault LLP

Notes:

- (1) The information as to residence and principal occupation has been furnished by the respective individuals.
- (2) Mr. Ritchie is the Chair of the Board.
- (3) Member of the Audit Committee.
- (4) Member of the Compensation and Governance Committee.
- (5) Mr. Braun was a director of Blackbird from November 9, 2009 until the Corporate Acquisition on January 4, 2019.
- (6) Mr. Lancaster is Chair of the Compensation and Governance Committee.
- (7) Member of the Reserves and Health, Safety & Environmental Committee.
- (8) Mr. Rossall is Chair of the Reserves and Health, Safety & Environmental Committee.
- (9) Ms. Anderson is Chair of the Audit Committee.
- (10) Independent Director.
- (11) Mr. Lancaster is President of GMT Exploration, which holds 15,562,373 Common Shares or 5.6% of the issued and outstanding Common Shares as at the date of this AIF. GMT Capital holds 37,675,762 Common Shares or 13.5% of the issued and outstanding Common Shares as at the date of this AIF. According to a Form 62-103F3 filed by GMT Capital on February 10, 2021 pursuant to National Instrument 62-103 (Part 4 – Alternative Monthly Reporting system), GMT Capital specifically disclaims any ownership or control over the Common Shares held by GMT Exploration and confirms that there is no agreement, commitment or understanding between GMT Capital and GMT Exploration with regards to the acquisition or disposition of, or the exercise of any of the voting or exercise rights attaching to, any of the Common Shares. Mr. Lancaster exercises control and direction over the Common and Convertible Preferred Shares held by GMT Exploration. The information as to securities beneficially owned has been furnished by Mr. Lancaster.
- (12) Mr. Tichio, as a current Partner of Riverstone Holdings LLC, and Mr. Shah, as a current Principal of Riverstone Holdings LLC, may be considered to exercise some degree of control and direction over the 35,440,357 Common Shares held by Riverstone V REL CNOR LP and the 70,711,226 Common Shares held by Riverstone Pipestone LP. Riverstone V REL CNOR LP and Riverstone Pipestone LP collectively hold 106,151,583 Common Shares or 38.0% of the issued and outstanding Common Shares as at the date of this AIF. The information as to securities beneficially owned has been furnished by Messrs Tichio and Shah.

The term of office of each of our directors expires at the next annual meeting of our shareholders.

As at the date of this AIF, our directors and officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, 20.1 million Common Shares or 7.2% of our issued and outstanding Common Shares. The information as to securities beneficially owned has been furnished by the directors and officers, as applicable.

Director and Officer Five Year Histories

Gordon M. Ritchie (Chair, Independent)

Mr. Ritchie was with RBC Capital Markets for 37 years, retiring from the position of Vice Chairman in 2016. From 2001 through 2005, Mr. Ritchie served as Managing Director and Head of RBC's Global E&P Energy Group. Previously, Mr. Ritchie spent six years in New York where he served as President and CEO of RBC's U.S. Broker/Dealer, RBC Dominion Securities Corporation (1993 to 1999), where he was responsible for development and execution of RBC Capital Markets' U.S. business strategy. From 1989 through 1993, Mr. Ritchie was Managing Director of RBC's International Corporate Finance Group based in London, England.

Mr. Ritchie has extensive experience in investment banking with RBC Capital Markets in Europe, the United States and Canada. Mr. Ritchie holds an MBA (1977) from the University of Western Ontario and a Bachelor of Economics (1975) from the University of Alberta. Mr. Ritchie has held securities industry regulatory designations in Canada, the U.K. and the U.S. and served for two years as a member of the New York area Advisory Committee to the New York Stock Exchange Board of Directors. Mr. Ritchie is the Chairman of the Board of Directors for Obsidian Energy Ltd. and previously served as the Lead Independent Director for Kinder Morgan Canada Limited.

Garth Braun (Independent)

Mr. Braun was previously the Chairman, President and Chief Executive Officer of Blackbird prior to the Corporate Acquisition on January 4, 2019. Mr. Braun is a seasoned oil and gas executive with over 20 years of oil and gas experience combined with 35 years of diversified business experience in finance and real estate. Mr. Braun led Blackbird through the successful acquisitions of two E&P companies, the divestiture of non-core Montney assets, the accumulation of its Montney land at Pipestone / Elmworth and the drilling of Blackbird's Elmworth Montney wells. Mr. Braun is also a founder and director of Stage Completions Inc., an innovative downhole completions company. Mr. Braun was previously the Chairman and Chief Executive Officer of an international oil and gas company, an investment banker and a principal of a private real estate development company that completed over \$1 billion in real estate development.

Mr. Braun has an Honours Degree in Business Administration from Simon Fraser University majoring in economics, finance and accounting.

William Lancaster (Independent)

Mr. Lancaster joined GMT Energy as Vice President Exploration and Production on January 1, 2000. Effective April 20, 2001, Mr. Lancaster was named President of GMT Energy. Mr. Lancaster resigned from his position with GMT Energy effective January 4, 2005, and has since then served as a member of the Board of Directors and President of GMT Exploration. Mr. Lancaster has also served on the Board of Directors of Coelacanth Energy Inc. since June 2022.

Mr. Lancaster graduated from the University of Colorado with a bachelor's degree in Geologic Engineering in 1978. Mr. Lancaster is a former president of the Colorado Oil and Gas Association, on the Board of Directors for the Western Energy Alliance, and is a member of the Rocky Mountain Association of Geologists, and the American Association of Petroleum Geologists.

John Rossall (Independent)

Mr. Rossall currently serves on the Board of Pipestone Energy and the board of Peyto Exploration and Development Corp, which he joined in May 2019. Mr. Rossall was the Executive Director, North America for Repsol Oil & Gas Canada Inc, retiring from this position in July 2018. In November 2011, Mr. Rossall joined Talisman Energy Inc. ("**Talisman**"), where he led Talisman's Canadian oil and gas business, and subsequently assumed responsibility for Repsol's North American business in May 2015 with the acquisition of Talisman by Repsol. Prior to joining Talisman, Mr. Rossall was President and Chief Executive Offer of ProspEx Resources, a TSX listed junior oil and gas company from 2004 to 2011. Previously, Mr. Rossall was the Vice-President of the North Business Unit of Burlington Resources Canada. Prior to the acquisition of Canadian Hunter Exploration by Burlington, Mr. Rossall led the Deep Basin business at Canadian Hunter. Mr. Rossall was also the Chairman of the Board of Governors of the Canadian Association of Petroleum Producers from December 2014 to April 2016.

Mr. Rossall holds a BASc in Chemical Engineering (1984) from the University of Waterloo and subsequently completed the Program for Management Development at the Harvard Business School.

Robert Tichio (Independent)

Mr. Tichio is a Partner of Riverstone Holdings LLC, a private equity firm that manages a portfolio of energy investments. Prior to joining Riverstone in 2006, Mr. Tichio was in the Principal Investment Area of Goldman Sachs, which manages the firm's private corporate equity investments. Mr. Tichio began his career at J.P. Morgan in the Mergers & Acquisition group, where he

concentrated on assignments that included public company combinations, asset sales, takeover defenses, and leveraged buyouts. Mr. Tichio currently serves on the Board of Directors of Permian Resources Corporation, Tritium pty, Hammerhead Energy Inc., and several private energy and decarbonization companies in the U.S. and Canada.

Mr. Tichio received his A.B. from Dartmouth College as a Phi Beta Kappa graduate and later received his M.B.A. with Distinction from Harvard Business School.

Jesal Shah (Independent)

Mr. Shah is a Managing Director of Riverstone Holdings LLC, a private equity firm that manages a portfolio of energy investments. Mr. Shah joined Riverstone in 2010 as an Associate and returned to Riverstone in 2015 after earning his M.B.A. Prior to joining Riverstone, Mr. Shah was an Investment Banking Analyst in the Global Energy Group at Credit Suisse. While at Credit Suisse, Mr. Shah worked on M&A transactions and capital markets financings, with a focus on the energy and power sector. Mr. Shah currently serves on the Boards of Directors of several public and private energy companies in the U.S. and Canada.

Mr. Shah graduated summa cum laude from Tufts University with a B.A. in Economics and Spanish, and received his M.B.A. from Harvard Business School.

Kimberly Anderson (Independent)

Ms. Anderson is currently the Chief Financial Officer of Heartland Generation. She joined the company in November 2019. Most recently, Ms. Anderson was Chief Financial Officer of Athabasca Oil Corporation ("**Athabasca**") from 2014 to 2019. Prior to Athabasca, Ms. Anderson held senior financial positions with Canadian energy and infrastructure companies, including Kanata Energy Ltd. and Provident Energy Ltd. Ms. Anderson has over 20 years of diversified experience in energy and finance, including debt and equity capital markets, mergers and acquisitions, treasury and risk management, and all aspects of corporate compliance functions.

Ms. Anderson is a Chartered Professional Accountant and holds a Bachelor of Commerce from the University of Calgary. She also currently serves on the Board of Directors of Renfrew Educational Services.

Paul Wanklyn (President and Chief Executive Officer, Non-Independent Director)

Mr. Wanklyn is the President and Chief Executive Officer of Pipestone Energy. Mr. Wanklyn was previously the President of Pipestone Oil Corp. (prior to its amalgamation with Blackbird to form Pipestone Energy) and a Partner at Grafton Asset Management. Mr. Wanklyn started his career at Canadian Hunter Exploration Ltd. in 1982, and ultimately was the company's British Columbia Exploration Manager. Since 1993, Mr. Wanklyn has co-founded and has acted as CEO in numerous private and public exploration and production companies with operations in Western Canada and the U.S. Mr. Wanklyn received an MSc. in Geology from the University of Colorado in 1985 and a B.Comm from the University of Alberta in 1981. He is an advisory board member of the University of Calgary, Hotchkiss Brain Institute, a Board member of private UK E&P exploration company, Connaught Energy, and a past Board member of the Explorers and Producers Association of Canada.

Dustin Hoffman (Chief Operating Officer)

Mr. Hoffman is the Chief Operating Officer of Pipestone Energy. Mr. Hoffman has over 25 years of professional experience, at Encana Corporation and its predecessor companies, where he held several senior management roles in different operating groups such as Deep Basin, Peace River Arch, Montney, Duvernay prior to joining Pipestone Energy as Senior Manager, D&C Sourcing. Mr. Hoffman is a Professional Engineer and holds a B.Sc. Chemical Engineering from the University of Alberta.

Craig Nieboer (Chief Financial Officer)

Mr. Nieboer is the Chief Financial Officer of Pipestone Energy. Mr. Nieboer has over 30 years of professional experience, including approximately 20 years in the Canadian and international oil and gas industries. He most recently served as Chief Financial Officer of TSX-listed CES Energy Solutions Corp. since 2008. Mr. Nieboer is a Chartered Accountant with a Bachelor of Commerce degree from the University of Calgary.

Dan van Kessel (Vice President, Corporate Development)

Mr. van Kessel is Vice President, Corporate Development at Pipestone Energy. Mr. van Kessel leads the business development, transaction structuring, investment evaluation, and financing activities for Pipestone Energy. Mr. van Kessel was previously Vice President, Corporate Development at Pipestone Oil Corp. (prior to its amalgamation with Blackbird to form Pipestone Energy) and Vice President at Grafton Asset Management. Prior to joining Grafton Asset Management, Mr. van Kessel worked as an investment banking associate for Barclays in the Global Natural Resources group. Mr. van Kessel graduated from the Richard Ivey School of Business at Western with an Honours Bachelor of Administration with a concentration in Finance.

Alyson Goldman (Corporate Secretary)

Ms. Goldman is the Corporate Secretary of Pipestone Energy and a Partner in the business law group at McCarthy Tétrault LLP since January 1, 2021. Ms. Goldman was previously a Partner at Burnet, Duckworth & Palmer LLP. Ms. Goldman has over 25 years of experience and her current practice focuses on securities and corporate law, including M&A, corporate finance, shareholder activism and corporate governance. Ms. Goldman holds an Honours Bachelor of Arts degree from Western University and a Bachelor of Laws degree from Queen's University and is also a Chartered Financial Analyst.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

To the knowledge of Pipestone Energy no director or officer is, as at the date of this AIF, or has been within the 10 years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including Pipestone Energy) that:

- (a) was subject to a cease trade order, an order similar to a cease trade order, or an order that denied the relevant company access to any exemption under securities legislation, and which in all cases was in effect for a period of more than 30 consecutive days (an "**Order**"), which Order was issued while the director was acting in the capacity as director, chief executive officer or chief financial officer of such company; or
- (b) was subject to an Order that was issued after the director ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer of such company.

Except as disclosed below, to the knowledge of Pipestone Energy no director or officer is, as at the date of this AIF, or has been within 10 years before the date of this AIF, a director or executive officer of any company (including Pipestone Energy) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Mr. Tichio was a director of Castex Energy I, LLC, the general partner of Castex Energy 2005 L.P. On October 16, 2017, Castex Energy 2005 L.P. and four affiliated debtors each filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas, Houston Division. On August 31, 2018, the Court ordered these bankruptcy cases closed. Mr. Tichio was a director of Castex Energy I, LLC at the time of such bankruptcy filing.

Mr. Tichio was a director of EP Energy Corporation. On October 3, 2019, EP Energy Corporation and certain of its direct and indirect subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the United

States Bankruptcy Court for the Southern District of Texas, Houston Division. Mr. Tichio was director of EP Energy Corporation at the time of such bankruptcy filing and remained a director until resigning effective October 1, 2020 with the emergence of EP Energy Corporation from Chapter 11.

Mr. Braun was the Chief Financial Officer of Huldra Silver Inc. ("**Huldra**") from June 23, 2010 to January 20, 2015. In July 2013, Huldra sought and obtained creditor protection under the *Companies' Creditors Arrangements Act* (Canada) (the "**CCAA**"). In November 2014, Huldra implemented its CCAA restructuring in accordance with the terms and conditions of its Plan of Compromise and Arrangement (the "**Plan**") under the CCAA. The Plan was approved by the creditors of Huldra on September 23, 2014 and sanctioned by the Supreme Court of British Columbia on October 10, 2014. Huldra exited creditor protection under the CCAA in November 2014.

Mr. Ritchie was a director of Gemini Corporation, a TSXV listed corporation from November 2012 to December 2016, and again in May 2017 to April 2018. In April 2018, ATB Financial, Gemini Corporation's senior secured creditor, applied to the Alberta Court of Queen's Bench for a receivership order, which was subsequently granted. FTI Consulting Canada Inc. was appointed as receiver of all of Gemini Corporation's assets, undertakings and properties. Shares of Gemini Corporation were cease-traded on April 19, 2018. Mr. Ritchie had acted as a director of Gemini Corporation within the year prior to the granting of the receivership order.

To the knowledge of Pipestone Energy, no director or officer has, within 10 years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or become subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold his assets.

Except as otherwise disclosed below, no director or officer of Pipestone Energy or shareholder holding a sufficient number of Common Shares to affect materially the control of Pipestone Energy has been subject to:

- a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or
- b) any penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable securityholder in deciding whether to vote for a director.

The foregoing information, not being within the knowledge of Pipestone Energy, has been furnished by the respective directors, officers and shareholders of Pipestone Energy.

Conflicts of Interest

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise.

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. No assurances can be given that opportunities identified by such Board of Directors members will be provided to us.

The ABCA provides that in the event 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. To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the ABCA and the amended and restated by-laws of the Company.

Legal Proceedings and Regulatory Actions

There are no legal proceedings Pipestone Energy is or was a party to, or that any of its property is or was the subject of, during

Pipestone Energy's most recent financial year, nor are any such legal proceedings known to Pipestone Energy to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current total assets of Pipestone Energy.

There are no: (a) penalties or sanctions imposed against Pipestone Energy by a court relating to securities legislation or by a securities regulatory authority since Pipestone Energy's inception; (b) other penalties or sanctions imposed by a court or regulatory body against Pipestone Energy that would likely be considered important to a reasonable investor in making an investment decision; or (c) settlement agreements Pipestone Energy entered into before a court relating to securities legislation or with a securities regulatory authority, in Pipestone Energy's most recent financial year.

Interests of Management and Others in Material Transactions

Other than as related to the Convertible Preferred Share Financing as disclosed in "*General Development of the Business – Financings*" and "*Description of Capital Structure – Convertible Preferred Shares*" in this AIF, there is no material interest, direct or indirect, of any: (a) director or executive officer of Pipestone Energy; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of Pipestone Energy's voting securities; or (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction within three years before the date of this AIF that has materially affected or is reasonably expected to materially affect Pipestone Energy.

Transfer Agent and Registrar

Effective February 23, 2021, the transfer agent and registrar for the Common and Preferred Shares is Odyssey Trust Company at its principal offices located in Calgary, Alberta. The Company's previous transfer agent was Computershare Investor Services Inc.

Material Contracts

Except for contracts entered into in the ordinary course of business, the only material contracts that the Company has entered into within the last financial year, or before the last financial year which are still in effect, which can reasonably be regarded as presently material, are the following:

1. The nomination agreement the Company entered with Al Mehwar (the "**Al Mehwar Nomination Agreement**"). Under the Al Mehwar Nomination Agreement, so long as Al Mehwar holds voting interests in the Company (on a diluted basis) greater than or equal to 10%, the Company will include one Al Mehwar nominee for election to the Board at the annual meetings of the Company (see "*Risk Factors – Significant Shareholder Influence of the Company*");
2. The Fourth Amended and Restated Credit Agreement (see "*Description of Capital Structure – Reserve-Based Loan*");
3. As part of the Convertible Preferred Share Financing, the Company entered into a registration rights agreement with Riverstone and GMT Capital (the "**Preferred Shareholder Registration Rights Agreement**") that provides for customary demand and piggy-back registration rights. The Preferred Shareholder Registration Rights Agreement provides for demand registration rights in favour of Riverstone and GMT Capital such that they are entitled to require Pipestone Energy to qualify by prospectus all or a portion of the Common Shares held by Riverstone and GMT Capital for a distribution to the public in Canada or the United States, provided such demand will result in a minimum offering size of \$25 million. Pipestone Energy is not required to act upon a registration demand more than two times in any 12-month period and is limited to a maximum of four registration demands. The Preferred Shareholder Registration Rights Agreement also provides for piggy-back registration rights. Thus, where Pipestone Energy proposes to make a distribution, Riverstone and GMT Capital have the right to include a number of its Common Shares in the distribution, subject to certain limitations, including the underwriters' right to limit the

number of Common Shares to be underwritten to ensure that the marketing of the distribution is not adversely or materially affected. All distribution expenses (except underwriters' commissions) will be paid by Pipestone Energy in connection with a demand registration or piggy-back registration. Pipestone Energy will indemnify Riverstone and GMT Capital and the several underwriters of a demand registration and piggy-back registration against certain liabilities and Riverstone and GMT Capital have agreed to indemnify the Company for certain liabilities in connection with a demand registration and piggy-back registration;

4. As part of the Convertible Preferred Share Financing, the Company entered into a nomination agreement with GMT Capital (the "**GMT Capital Nomination Agreement**"). Under the GMT Capital Nomination Agreement, so long as GMT Capital holds voting interests in the Company (on a diluted basis) greater than or equal to 10%, the Company will include one GMT Capital nominee for election to the Board at annual meetings of the Company; and
5. As part of the Convertible Preferred Share Financing, the Company entered into a nomination agreement with Riverstone Pipestone LP (the "**Riverstone Nomination Agreement**"). Under the Riverstone Nomination Agreement, (a) so long as Riverstone holds voting interests in the Company (on a diluted basis) greater than or equal to (a) 20%, the Company will include two Riverstone nominees for election at annual meetings of the Company; or (b) 10%, the Company will include one Riverstone nominee for election at annual meetings of the Company.

Copies of the foregoing may be viewed on Pipestone Energy's profile on SEDAR at www.sedar.com.

Interests of Experts

As at the date hereof, the designated professionals of McDaniel, the Company's independent reserves petroleum consultants, as a group, beneficially own, directly or indirectly, less than 1% of the outstanding Common Shares.

Ernst & Young LLP are the external auditors of the Company and have confirmed that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Professional Accountants of Alberta.

Additional Information

Additional information relating to the Company can be found on the SEDAR website at www.sedar.com. Additional financial information is provided in the audited consolidated financial statements and Management's Discussion and Analysis of the Company for the years ended December 31, 2022 and 2021, which are accessible on the SEDAR website at www.sedar.com.

Audit Committee Information

Audit Committee Charter

The full text of our Audit Committee charter is included in Appendix "C" of this Annual Information Form.

Composition of the Audit Committee

The members of our Audit Committee are Ms. Anderson (Chair), Messrs. Lancaster, Ritchie, Rossall and Braun each of whom are independent and financially literate. The Company has adopted the definition of "independence" as set out in Section 1.4 of National Instrument 52-110 – Audit Committees. The relevant education and experience of each Audit Committee member is outlined below.

Kimberly Anderson

Ms. Anderson is currently the Chief Financial Officer of Heartland Generation. She joined the company in November 2019. Most recently, Ms. Anderson was Chief Financial Officer of Athabasca from 2014 to 2019. Prior to Athabasca, Ms. Anderson held senior financial positions with Canadian energy and infrastructure companies, including Kanata Energy Ltd. and Provident Energy Ltd. Ms. Anderson has over 20 years of diversified experience in energy and finance, including debt and equity capital markets, mergers and acquisitions, treasury and risk management, and all aspects of corporate compliance functions.

Ms. Anderson is a Chartered Professional Accountant and holds a Bachelor of Commerce from the University of Calgary. She also currently serves on the Board of Directors of Renfrew Educational Services.

William Lancaster

Mr. Lancaster joined GMT Energy as Vice President Exploration and Production on January 1, 2000. Effective April 20, 2001, Mr. Lancaster was named President of GMT Energy. Mr. Lancaster resigned from his position with GMT Energy effective January 4, 2005, and has since then served as a member of the Board of Directors and President of GMT Exploration. Mr. Lancaster has also served on the Board of Directors of Coelacanth Energy Inc. since June 2022.

Mr. Lancaster graduated from the University of Colorado with a bachelor's degree in Geologic Engineering in 1978. Mr. Lancaster is a former president of the Colorado Oil and Gas Association, on the Board of Directors for the Western Energy Alliance, and is a member of the Rocky Mountain Association of Geologists, and the American Association of Petroleum Geologists.

Gordon Ritchie

Mr. Ritchie was with RBC Capital Markets for 37 years, retiring from the position of Vice Chairman in 2016. From 2001 through 2005, Mr. Ritchie served as Managing Director and head of RBC's Global E&P Energy Group. Previously, Mr. Ritchie spent six years in New York where he served as President and CEO of RBC's U.S. Broker/Dealer, RBC Dominion Securities Corporation (1993 to 1999), where he was responsible for development and execution of RBC Capital Markets U.S. business strategy. From 1989 through 1993, Mr. Ritchie was Managing Director of RBC's International Corporate Finance Group based in London, England.

He has extensive experience in investment banking with RBC Capital Markets in Europe, the United States and Canada. Mr. Ritchie holds an MBA (1977) from the University of Western Ontario and a Bachelor of Economics (1975) from the University of Alberta. Mr. Ritchie has held securities industry regulatory designations in Canada, the U.K. and the U.S. and served for two years as a member of the New York area Advisory Committee to the New York Stock Exchange Board of Directors. Mr. Ritchie is the Chairman of the Board of Directors for Obsidian Energy Ltd. and previously served as the Lead Independent Director for Kinder Morgan Canada Limited.

Garth Braun

Mr. Braun was previously the Chairman, President and Chief Executive Officer of Blackbird prior to its amalgamation with Pipestone Oil Corp. on January 4, 2019 to form Pipestone Energy. Mr. Braun is a seasoned oil and gas executive with over 20 years of oil and gas experience combined with 35 years of diversified business experience in finance and real estate. Mr. Braun led Blackbird through the successful acquisitions of two E&P companies, the divestiture of non-core Montney assets, the accumulation of its Montney land at Pipestone / Elmworth and the drilling of Blackbird's Elmworth Montney wells. Mr. Braun is also a founder and director of Stage Completions Inc., an innovative downhole completions company. Mr. Braun was previously the Chairman and Chief Executive Officer of an international oil and gas company, an investment banker and a principal of a private real estate development company that completed over \$1 billion in real estate development.

Mr. Braun has an Honours Degree in Business Administration from Simon Fraser University majoring in economics, finance and accounting.

Pre-Approval of Policies and Procedures

Our Audit Committee must pre-approve all non-audit services to be provided to us by our external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by our Audit Committee from time to time.

External Auditor Service Fees

The following table summarizes the fees paid by us to our external auditors, Ernst & Young LLP, during the years ended December 31, 2022, 2021 and 2020. The amounts disclosed exclude administrative charges.

YEAR	Audit Fees ⁽¹⁾ (\$)	Audit Related Fees ⁽²⁾ (\$)	Tax Fees ⁽³⁾ (\$)
2022	\$140,000	\$45,000	\$28,250
2021	\$97,500	\$36,000	\$28,250
2020	\$119,500	\$24,000	\$7,000

Notes:

- (1) Represents fees billed by our external auditor for audit services.
- (2) Represents fees billed for assurance related services by our external auditor that are reasonably related to the performance of the audit or review of our financial statements that are not reported under audit fees.
- (3) Represents fees billed for professional services rendered by our external auditor for tax compliance, tax advice and tax planning.

Appendix "A"

Form 51-101F2 - Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

Form 51-101F2

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

1. We have evaluated the Company's reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, 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 plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated hereof that we have evaluated and reported on to the Company's Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation/Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
McDaniel	December 31, 2022	Canada	-	\$1,993,888.6	-	\$1,993,888.6

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

Calgary, Alberta, Canada

February 13, 2023

Appendix "B"

Form 51-101F3 - Report of Management and Directors on Oil and Gas Disclosure

Form 51-101F3

Management of Pipestone Energy Corp. ("**Pipestone Energy**") is responsible for the preparation and disclosure of information with respect to Pipestone Energy's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated Pipestone Energy's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of Pipestone Energy has:

- (a) reviewed Pipestone Energy's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the content and filing of this report.

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

(signed) "*John Rossall*"
John Rossall
Director and Chairman of the Reserves Committee

(signed) "*Gordon Ritchie*"
Gordon Ritchie
Chairman

(signed) "*Paul Wanklyn*"
Paul Wanklyn
President and Chief Executive Officer

(signed) "*Dustin Hoffman*"
Dustin Hoffman
Chief Operating Officer

March 8, 2023

Appendix "C"

Audit Committee Charter

PIPESTONE ENERGY CORP. Audit Committee Mandate (Effective January 9, 2019)

Policy Statement

Pipestone Energy Corp. (the "**Corporation**") has established and maintains an Audit Committee, (the "**Committee**") composed entirely of independent directors, to assist the Board of Directors (the "**Board**") in carrying out its oversight responsibility with respect to public reporting related to the Corporation's internal controls, financial reporting and risk management processes. The Committee will be provided with resources commensurate with the duties and responsibilities set out herein and assigned to it by the Board from time to time, including administrative support. If determined necessary by the Committee, it will have the discretion to institute investigations of improprieties, or suspected improprieties within the scope of its responsibilities, including the standing authority to retain special counsel or experts.

Composition

1. The Committee shall consist of at least three directors. The Board shall appoint the members of the Committee. The Board shall appoint one member of the Committee to be the chair of the Committee (the "**Chair**").
2. Each director appointed to the committee by the Board shall be "independent" as required under the applicable securities laws and the applicable rules of any stock exchange on which the securities of the Corporation are listed.
3. Each member of the Committee shall be "financially literate" as required under the applicable securities laws, including without limitation National Instrument 52-110 - Audit Committees ("**NI 52-110**"). In order to be financially literate, a director must have 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 Corporation's financial statements. If available, at least one member shall have "accounting or related financial management expertise", meaning the ability to analyze and interpret a full set of financial statements, including the notes attached thereto, in accordance with Canadian generally accepted accounting principles.
4. A director appointed by the Board to the Committee shall be a member of the Committee until replaced by the Board or until his or her resignation.

Meetings and Operations

1. The Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chair and whenever a meeting is requested by the Board, a member of the Committee, the external auditors (the "**Auditors**"), or an officer of the Corporation. Meetings of the Committee shall correspond with the review of the quarterly and annual financial statements and the associated management's discussion and analysis ("**MD&A**").
2. Notice of each meeting of the Committee shall be given to each member of the Committee and to the Auditors, who shall be entitled to attend each meeting of the Committee and who shall attend whenever requested to do so by a member of the Committee.
3. A quorum for the transaction of business at a meeting of the Committee shall consist of two members of the Committee.

4. A member or members of the Committee may participate in a meeting of the Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.
5. In the absence of the Chair, the members of the Committee shall choose one of the members present to be chair of the meeting. In addition, the members of the Committee shall choose one of the persons present to be the secretary of the meeting.
6. The President and Chief Executive Officer, the Chief Financial Officer and other members of senior management shall be invited to attend meetings of the Committee upon the request of the Committee; subject, however, to the requirement that the Committee (i) hold in camera sessions of the members of the Committee, without management representatives present at every meeting of the Committee, and (ii) meet with the Auditors separately and independent of management at every meeting at which the Auditors are in attendance.
7. Minutes shall be kept of all meetings of the Committee.

Authority and Reporting

1. In discharging its duties and responsibilities, the Committee shall have the authority to:
 - (a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;
 - (b) discuss with the management of the Corporation, its subsidiaries and affiliates and staff of the Corporation, any affected party, contractors and consultants of the Corporation and the Auditors, such accounts, records and other matters as any member of the Committee considers necessary and appropriate;
 - (c) engage independent counsel and other advisors (including a second firm of external auditors) as it determines necessary to carry out its duties; and
 - (d) set and pay the compensation for any advisors employed by the Committee.
2. The Committee shall after each meeting, report to the Board the results of its activities and any reviews undertaken and make recommendations to the Board as deemed appropriate.

Primary Duties and Responsibilities

1. The Committee's primary duties and responsibilities regarding its audit function are to:
 - (a) review with the Auditors the audit function generally, the objectives, staffing, locations, co-ordination, and scope of proposed audits of the financial statements of the Corporation;
 - (b) review with management and the external auditors, and recommend to the Board for approval and release to shareholders, the quarterly and annual financial statements of the Corporation, together with related reports to shareholders, MD&A associated with such financial statements and, when applicable, other public filings (such as prospectus or annual information forms) containing financial disclosures;
 - (c) review with the auditors and management, and monitor the management of, the principal risks that could affect the financial reporting of the Corporation;
 - (d) review and assess the framework of and periodically consider the integrity of the Corporation's financial reporting process and system of internal controls regarding financial reporting and accounting compliance through discussions with management and the auditor;

- (e) consider the independence and performance of the Corporation's auditors;
- (f) deal directly with the auditors to approve the annual external audit plan, other services (if any) and associated fees;
- (g) approve the audit engagement and consider the external audit process and results;
- (h) provide an avenue of communication among the auditors (both external and internal, if any), management and the Board, and direct the external auditors to report directly to the Committee;
- (i) establish and monitor procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the anonymous submission by employees of concerns regarding questionable accounting or auditing matters or other "whistleblower" issues, and review the minutes of any Committee meetings held in connection with any subsidiary companies of the Corporation; and
- (j) establish and monitor procedures for information security and cyber risk protection for the Corporation.

3. The Committee shall, in connection with the financial aspects of the Corporation's business:

- (a) review the annual external audit plan with the Corporation's auditors and with management and approve the engagement letter relating thereto;
- (b) discuss with management and the auditors any proposed changes in major accounting policies or principles, the presentation and effect of significant risks and uncertainties and key estimates and judgements of management that may be material to financial reporting;
- (c) review with management and with the auditors significant financial reporting issues arising during the most recent fiscal period and the resolution or proposed resolution of such issues;
- (d) review any problems experienced or concerns expressed by the auditors in performing an audit, including any restrictions imposed by management or significant accounting issues on which there was a disagreement with management;
- (e) review with management the process of identifying, monitoring and reporting the Corporation's risk management policies and procedures and the principal risks affecting financial reporting;
- (f) review and evaluate any recommendations of the auditors and decide the appropriate course of action;
- (g) consider consistency of the data reported in the financial statements, annual and quarterly reports and related public disclosure documents;
- (h) review audited annual financial statements and related documents in conjunction with the report of the auditors and significant variances between comparative reporting periods as set out in the MD&A;
- (i) review, independently of management, and without management present, the results of the annual external audit, the audit report thereon and the auditor's review of the related MD&A, and discuss with the auditor the quality of accounting principles used, any alternative treatments of financial information that have been discussed with management, the ramifications of their use and the auditor's preferred treatment and any other material communication with management;
- (j) consider and review with management:

- (i) all unadjusted errors identified by the external auditors;
- (ii) the internal control memorandum or management letter containing the recommendations of the auditors and management's response, if any, including any evaluation of the adequacy and effectiveness of the internal financial controls of the Corporation and subsequent follow-up to any identified weakness;
- (k) review with management and the auditors the quarterly unaudited financial statements and MD&A before release to the public;
- (l) before release, review and if appropriate, recommend for approval by the Board, all public disclosure documents containing audited or unaudited financial information, including any prospectus, annual reports, annual information forms, MD&A and press releases announcing quarterly or annual financial results;
- (m) review and approve the Corporation's hiring policies regarding employees and former employees of the present and former auditors;
- (n) review with management the Corporation's relationship with regulators and the timelines and accuracy of the Corporation's filings with regulatory agencies; and
- (o) review with management all related party transactions and the development of policies and procedures related to those transactions.

Auditors

1. The Committee shall:
 - (a) consider the independence and performance of the auditors and annually recommend to the Board the appointment or discharge of the auditor when circumstances are warranted and recommend to the Board the compensation of the auditors;
 - (b) pre-approve all non-audit services to be provided to the Corporation or its subsidiary entities by the auditors, or the auditors of any of the Corporation's subsidiary entities;
 - (c) when there is to be a change of auditors, review all issues and provide documentation related to the change, including the information to be included in the Notice of Change of Auditors and related documentation required pursuant to National Instrument 51-102 — Continuous Disclosure Obligations, with respect to a change of auditors (or any successor legislation) and the planned steps for an orderly transition period;
 - (d) review all material written communications between the auditor and management; and
 - (e) review all reportable events, including disagreements, unresolved issues and consultations, as defined by applicable securities policies, on a routine basis, whether or not there is to be a change of auditors.

Financing Matters

1. The Committee shall:
 - (a) review all securities offering documents (including documents incorporated therein by reference) of the Corporation;
 - (b) review findings, if any, from examinations or reviews performed by regulatory agencies with respect to

financial matters;

- (c) review management's consideration of the Corporation's compliance with laws and regulations;
- (d) review management's assessment of current and expected future compliance with covenants under any financing agreements;
- (e) if requested by the Board, review the proposed repurchase of public and private debt, equity and hybrid securities; and
- (f) in consultation with management understand the Corporation's capital structure and financial risks arising from exposure to such things as commodity prices, interest rates, foreign currency exchange rates and credit and review the management of these risks including any proposed hedging of the exposures, including receiving a summary report of the hedging activities and hedge-related instruments.

Other

1. The Committee shall consider the amount and terms of any insurance to be obtained or maintained by the Corporation with respect to risks inherent in its operations and potential liabilities incurred by the directors or officers in the discharge of their duties and responsibilities.
2. The Committee shall consider the appointments of the Chief Financial Officer and any key financial managers who are involved in the financial reporting process.
3. The Committee shall enquire into and determine the appropriate resolution of any conflict of interest in respect of audit or financial matters, which are directed to the Committee by any member of the Board, a shareholder of the Corporation, the auditors, or management.
4. The Committee shall review, on an annual basis this mandate and recommend any changes to the Board.
5. The Committee will perform any other activities consistent with this mandate, the Corporation's bylaws and applicable laws as the Committee or the Board deems necessary or appropriate.

Scope and Reliance

1. While the Committee has the responsibilities, duties and authorities herein, it is not required to plan or conduct audits or to determine that the Corporation's financial statements and disclosures are complete and accurate or are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the auditors. The Committee, its Chair and any of its members who have accounting or related financial management experience or expertise, are members of the Board, appointed to the Committee to provide broad oversight to the financial disclosure, financial risk and control related activities of the Corporation, and are specifically not accountable nor responsible for the day-to-day operation of such activities. Although designation of a member or members as being "financially literate" or a "financial expert" is based on each such individual's education and experience, which that individual will bring to bear in carrying out his or her duties on the Committee, designation as being "financially literate" or a "financial expert" does not impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Committee and Board in the absence of such designation. Rather, the role of any financially literate individual or financial expert, like the role of all Committee members, is to oversee the process and not to certify or guarantee the internal or external audit of the Corporation's financial information or public disclosure.
2. Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Committee shall be entitled to rely on (i) the integrity of those persons or organizations within and outside the Corporation from which it receives information, (ii) the accuracy of the information provided to the Committee by

such persons or organizations, and (iii) representations made by management of the Corporation, the external auditors of the Corporation, independent counsel, and other advisors and experts to the Corporation and its subsidiaries.

Pre-Approval Policies and Procedures

The Audit Committee has established a pre-approval policy and procedures for the engagement of non-audit services. The Audit Committee must approve all engagements for non-audit services which are expected to exceed \$30,000 per engagement before the engagement may commence. For engagements for non-audit services which are expected to be less than \$30,000 the engagement may commence upon approval by the Chair of the Audit Committee with all members being informed of the service at the next meeting of the Committee. All recommendations for services will be submitted by the Chief Financial Officer.