JOURNEY
ENERGY INC.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2020

March 23, 2021

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CONVENTIONS

Words importing the singular number include the plural and vice versa, and words importing any gender include all genders.

All dollar amounts set forth in this AIF (as defined herein) are in Canadian dollars unless otherwise indicated.

All financial information in this AIF has been presented in accordance with GAAP (as defined herein).

Certain terms used in this AIF are defined under the headings "*Glossary*", "*Presentation of Oil and Gas Reserves and Production Information - Glossary of Selected Oil and Gas Terms*" and "*Presentation of Oil and Gas Reserves and Production Information - Selected Abbreviations*". Certain other terms used in this AIF but not defined herein are defined in NI 51-101 (as defined herein) and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF constitute forward-looking statements. These statements relate to future events or the Company's (as defined herein) future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "contemplate", "continue", "estimate", "expect", "intend", "propose", "might", "may", "will", "shall", "project", "should", "could", "would", "believe", "predict", "forecast", "pursue", "potential" and "capable" 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. 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. These statements speak only as of the date of this AIF. In addition, this AIF may contain forward-looking statements and forward-looking information attributed to third party industry sources.

In particular, this AIF contains forward-looking statements pertaining to the following:

- the reserve potential of the Company's assets;
- the estimated production and decline rates from the Company's assets;
- the Company's growth strategy through accretive acquisitions and organically;
- the Company's plans to optimize legacy pools through horizontal drilling and water floods;
- the Company's expectations to repay its senior secured term debt as it matures;
- the Company's targets for future growth;
- expectations with respect to future opportunities and stability;
- expectations with respect to future funds flow, net debt, Capital Efficiencies (as defined herein), payout ratios and other financial results;
- the Company's capital expenditure programs;
- the estimated quantity and value of the Company's proved and probable reserves;
- the Company's estimates of future interest and foreign exchange rates;
- the cash available for the funding of capital expenditures;
- the Company's environmental considerations;
- the Company's expectations regarding commodity prices and costs;
- the timing of commencement of certain of the Company's operations and the level of production anticipated by the Company and production method efficacy;
- expectations regarding the Company's tax horizon;
- the potential for production disruption and constraints;
- supply and demand fundamentals for crude oil and natural gas;

- the expectation that supply in excess of current pipeline and refining capacity is expected to continue;
- the Company's access to adequate pipeline capacity;
- the Company's access to third-party infrastructure;
- the Company's hedging policy;
- the Company's plans for, funding for and planned exploration and development activities, the expected results for such activities and how such activities are expected to be funded;
- the Company's abandonment and reclamation cost expectations;
- the Company's treatment under governmental regulatory regimes and tax laws;
- the Company's future general and administrative expenses;
- the Company's access to capital and overall strategy, development and drilling plans for all of the Company's assets; and
- expectations on how the Company will manage exploration, production and marketing risks.

With respect to forward-looking statements contained in this AIF, assumptions have been made regarding, among other things:

- future crude oil, NGL (as defined herein) and natural gas prices;
- the Company's ability to obtain qualified staff and equipment in a timely and cost–efficient manner;
- the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts its business and any other jurisdictions in which the Company may conduct its business in the future;
- the Company's ability to market production of oil and natural gas successfully to customers;
- the Company's future production levels;
- the applicability of technologies for recovery and production of the Company's reserves;
- the recoverability of the Company's reserves;
- future capital expenditures to be made by the Company;
- future cash flows from production meeting expectations;
- future sources of funding for the Company's capital program;
- the Company's future debt levels;
- geological and engineering estimates in respect of the Company's reserves;
- the geography of the areas in which the Company is conducting exploration and development activities;
- the impact of competition on the Company; and
- the Company's ability to obtain financing on acceptable terms.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and included elsewhere in this AIF, including:

- the Company's liquidity and additional funding requirements;
- current global financial conditions, including: the impact of the COVID 19 pandemic; fluctuations in interest rates, foreign exchange rates and stock market volatility;
- general economic, market and business conditions;
- volatility in market prices and demand for crude oil and natural gas and hedging activities related thereto;
- seasonality of the Canadian oil and gas industry;
- risks related to the exploration, development and production of oil and natural gas reserves;
- risks related to the timing of completion of the Company's projects;
- competition for, among other things, capital, the acquisition of reserves and resources and skilled personnel;
- operational hazards;
- actions by governmental authorities, including changes in government regulation and taxation;
- environmental risks and hazards;

- risks inherent in the exploration, development and production of oil and natural gas which may create liabilities to the Company in excess of the Company's insurance coverage;
- cost of new technologies;
- failure to accurately estimate abandonment and reclamation costs;
- failure of third parties' reviews, reports and projections to be accurate;
- the availability of capital on acceptable terms;
- political risks;
- climate change;
- changes to royalty or tax regimes;
- the failure of the Company or the holders of certain licenses or leases to meet specific requirements of such licenses or leases;
- claims made in respect of the Company's properties or assets;
- indigenous claims;
- unforeseen title defects;
- risks arising from future acquisition activities;
- risks associated with the realization of anticipated benefits of acquisitions and dispositions;
- hedging strategies;
- potential conflicts of interest;
- the potential for management estimates and assumptions to be inaccurate;
- risks associated with establishing and maintaining systems of internal controls;
- risks related to the reliance on historical financial information, including that historical financial information does not reflect the added costs that the Company expects to incur as a public entity;
- restrictions contained in the Company's Credit Agreement (as defined herein);
- additional indebtedness;
- failure to engage or retain key personnel;
- potential losses which would stem from any disruptions in production, including work stoppages or other labour difficulties, or disruptions in the transportation network on which the Company is reliant;
- uncertainties inherent in estimating quantities of oil and natural gas reserves;
- failure to acquire or develop replacement reserves;
- geological, technical, drilling and processing problems, including the availability of equipment and access to properties;
- failure by counterparties to make payments or perform their operational or other obligations to the Company in compliance with the terms of contractual arrangements between the Company and such counterparties;
- disclosure of confidential information of the Company; and
- other factors discussed under "*Risk Factors*".

Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive.

In addition, information and statements in this AIF relating to "reserves" are deemed to be forward-looking information and 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 described can be profitably produced in the future. See also "*Note on Reserves Data*".

There are numerous uncertainties inherent in estimating quantities of oil and natural gas and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this AIF are estimates only. In general, estimates of economically recoverable oil and natural gas and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Journey's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. See also "*Note on Reserves Data*".

The forward-looking statements included in this AIF are expressly qualified by this cautionary statement and, except as otherwise indicated, are made as of the date of this AIF. The Company does not undertake any obligation to publicly update or revise any forward-looking statements or departures from them except as required by applicable securities laws.

ACCESS TO DOCUMENTS

Any document referred to in this AIF and described as being accessible on the SEDAR website at www.sedar.com (including those documents referred to as being incorporated by reference in this AIF) may be obtained free of charge from the Company at Suite 700, 517 – 10th Avenue SW, Calgary, Alberta T2R 0A8.

NON-GAAP MEASURES

Journey uses terms within this AIF that do not have a standardized prescribed meaning under GAAP (as defined herein) and these measurements may not be comparable with the calculation of similar measurements of other entities.

Throughout this AIF the Company uses the terms "funds flow", "netback", and "net debt". These terms do not have a standardized prescribed meaning under GAAP and these measurements may not be comparable with the calculation of similar measurements by other entities.

"**Funds Flow**" is a non-GAAP measure and is calculated based on cash flow from operating activities and then removing the impact of: the change in non-cash working capital; transaction costs; and decommissioning expenditures. Journey believes the timing of collection, payment or incurrence of these items involves a high degree of discretion and as such may not be useful for evaluating Journey's operating performance. Management utilizes Funds Flow as a key measure to assess the ability of the Company to finance operating activities and capital expenditures. Funds Flow should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with GAAP as an indication of Journey's performance.

	Year ended		
	December 31, 2020	**December 31, 2019**	**December 31, 2018**
Cash flow from operating activities	11,605	27,748	15,415
Transaction costs	23	27	194
Financing costs	1,912	-	-
Decommissioning expenditures	480	2,236	1,288
Change in non-cash working capital	(545)	(1,593)	1,396
Funds flow	13,475	26,805	18,293

"**Netback**" is a non-GAAP measure and is calculated on a per boe basis and is determined by taking the average selling prices of all commodities (excluding financial hedging gains and losses), less royalties, transportation costs and operating expenses and dividing the result by the volumes sold. Netback is utilized by Journey to analyze the operating performance of its petroleum and natural gas assets against prior periods and against its peers.

“**Net debt**” is a non-GAAP measure and is calculated by taking the principal amount owing of all borrowings plus all other current liabilities (excluding derivative contract fair values and decommissioning liabilities) less current assets (excluding derivative contract fair values). Net debt is used by management in its capital budgeting to assess efficiency, liquidity and general financial strength of the Company. It is also used as a comparison metric to assess relative financial strength in relation to Journey’s peers.

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

Journey has adopted the standard of 6 Mcf:1 Bbl when converting natural gas to oil equivalent. Boe’s may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf:1 Bbl, utilizing a conversion ratio at 6 Mcf:1 Bbl may be misleading as an indication of value.

The discounted and undiscounted net present values of future net revenues attributable to reserves do not represent the fair market value of reserves.

There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided in this AIF are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided in this AIF.

The estimates of reserves and future net revenue for individual properties in this AIF may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Glossary of Selected Oil and Gas Terms

In this AIF, unless otherwise indicated or the context otherwise requires, the following terms have the meaning set forth below. These definitions are generally as set forth in the COGE Handbook (as defined herein) and NI 51-101 and are reproduced below for the convenience of the reader.

°API means the American Petroleum Institute gravity, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid’s API gravity is greater than 10, it is lighter and floats on water; and if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids.

API means the American Petroleum Institute.

basin means a large natural depression on the earth’s surface in which sediments generally brought by water accumulate.

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

company gross reserves means the Company’s working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company.

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 cost means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

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

exploration costs means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

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

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.

finding, development and acquisition costs means the identified capital expenditures associated with the addition of proved plus probable reserves including changes in future development capital, divided by the associated reserve additions during the period that the expenditures were incurred.

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

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are 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 paragraph (a).

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

future income taxes when used are estimated:

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to Journey’s oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

gross means:

(a) in relation to a 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;

(b) in relation to wells, the total number of wells in which a company has an interest; and

(c) in relation to properties, the total area of properties in which a company has an interest.

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.

liquids means crude oil and natural gas liquids.

net means:

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

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

(c) in relation to a 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.

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.

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. Reserves are classified according to the degree of certainty associated with the estimates.

reservoir means a porous and permeable underground rock formation containing a natural accumulation of petroleum that is confined by impermeable rock or water barriers, is separate from other reservoirs and is characterized by a single pressure system.

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

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.

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

Selected Abbreviations

In this AIF, unless otherwise indicated or the context otherwise requires, the following abbreviations shall have the meaning set forth below:

Crude Oil and Natural Gas Liquids	
bbl(s)	Barrel(s) of oil
bbl/d	barrels of oil per day
boe	barrel of oil equivalent
boe/d	barrel of oil equivalent per day
Mbbls	thousand barrels
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
NGLs	natural gas liquids
WTI	West Texas Intermediate

Natural Gas	
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Other	
$ or dollars	Canadian dollars
$000	thousands of dollars
MM$	millions of dollars
$/bbl	dollars per barrel of oil
$/boe	dollars per barrel of oil equivalent
$/Mcf	dollars per thousand cubic feet
$US or US$	United States dollars
3D	three dimensional
m	metre
AECO	a notional market point on the NGTL system, located at the AECO 'C' hub in Southeastern Alberta, where the purchase and sale of natural gas is transacted
Henry Hub	a central delivery location, located near Louisiana's Gulf Coast connecting several intrastate and interstate pipelines, that serves as the official delivery location for futures contracts on the NYMEX
MW	Megawatts of electricity
WTI	means West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade

Oil and Gas Advisories

The term "boe" or barrels of oil equivalent and "Mcfe" or thousand cubic feet equivalent may be misleading, particularly if used in isolation. A boe or Mcfe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

This annual information form contains certain oil and gas metrics, including reserve life index, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Corporation's performance; however, such measures are not reliable indicators of the future performance of the Corporation and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Selected Conversions

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
bbls	cubic metres	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
sections	acres	640
acres	sections	0.0015625

NOTE ON RESERVES DATA

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The qualitative certainty levels referred to in the definitions set forth in the "*Presentation of Oil and Gas Reserves and Production Information - Glossary of Selected Oil and Gas Terms*" in this AIF are applicable to individual reserve 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:

(a) at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) 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 will be 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.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

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.

GLOSSARY

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

AB LLR Program means the Alberta Licensee Liability Rating Program.

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

Action Plan means "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" released by the Government of Canada.

AER means the Alberta Energy Regulator.

AIF means this annual information form.

AIMCo means the Alberta Investment Management Company.

Alberta Royalty Framework means the *Mines and Minerals (New Royalty Framework) Amendment Act* (Alberta).

ALSA means the *Alberta Land Stewardship Act*.

ALUF means the Alberta Land Use Framework.

Audit Committee means the audit committee of the Board.

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

Bulletin 16 means Bulletin 2019-16: Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater decision.

Bulletin 21 means Bulletin 2019-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater decision.

Capital Efficiency means the aggregate amount of capital expenditures (including drilling, well completion, associated equipment and connecting to infrastructure) associated with generating new production, divided by the average production rate over the initial 365 day period.

CCAA means the *Companies' Creditors Arrangement Act, RSC 1985, C-36* as amended.

CCIR means the *Carbon Competitiveness Incentive Regulation* (Alberta).

CEO means Chief Executive Officer.

CETA means the Comprehensive Economic and Trade Agreement.

Changes has the meaning set out in "*Industry Conditions – Liability Management Rating Programs – Alberta*".

CLA means the *Climate Leadership Act* (Alberta).

CLIA means the *Climate Leadership Implementation Act* (Alberta).

Common Shares means the common shares in the capital of the Company.

COO means the Chief Operating Officer.

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

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

Directive 013 means Directive 013: Suspension Requirements for Wells.

ESTMA means the *Extractive Sector Transparency Measures Act* (Canada).

GAAP means generally accepted accounting principles for publicly accountable enterprises (being International Financial Reporting Standards as adopted by the Canadian Accounting Standards Board).

GHG means greenhouse gas.

GLJ means GLJ Ltd., independent petroleum consultants of Calgary, Alberta.

GLJ Report means the report prepared by GLJ dated March 9, 2021 evaluating the crude oil, natural gas and natural gas liquids reserves attributable to all of the assets of Journey as at December 31, 2020. The related Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 and Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached hereto as Appendices "A" and "B", respectively.

Governance & Compensation Committee means the corporate governance & compensation committee of the Board.

INDC means Intended Nationally Determined Contribution.

IWCP means the Inactive Well Compliance Program.

Journey or the **Company** means Journey Energy Inc.

Kiwetinohk or **KRC** means Kiwetinohk Resources Corp.

LARP means the Lower Athabasca Regional Plan.

LMR means the liability management rating, reflecting the results of a comparison of a company's deemed assets to their deemed liabilities.

MRF means the Modernized Royalty Framework for Alberta.

NAFTA means the North American Free Trade Agreement.

NDC means Nationally Determined Contributions.

NEB means the National Energy Board of Canada.

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

OGCA means the *Oil and Gas Conservation Act* (Alberta).

OPEC means the Organization of Petroleum Exporting Countries.

Order has the meaning set out in "*Directors and Officers – Cease Trade Orders, Bankruptcies, Penalties or Sanctions – Cease Trade Orders*".

Orphan Fund has the meaning set out in "*Industry Conditions – Liability Management Rating Programs – Alberta*".

Paris Agreement has the meaning set out in "*Industry Conditions – Climate Change Regulation – Federal*".

Preferred Shares means the preferred shares in the capital of the Company.

Promissory Notes (2016) means the promissory notes issued to AIMCo in the private placement on October 6, 2016 in the aggregate face value amount of $30,000,000 and bearing interest at 7.65% per annum.

Promissory Notes (2018) means the promissory notes issued to AIMCo in the private placement on January 31, 2018 in the aggregate face value amount of $22,000,000 and bearing interest at 7.65% per annum.

Prosperity Act means the *Jobs, Growth and Long-term Prosperity Act (Canada)*.

PSP means Infra-PSP Partners Inc., a wholly-owned subsidiary of PSP Investments.

Redwater means the Supreme Court of Canada's decision *Redwater Energy Corporation (Re), Orphan Well Association v. Grant Thornton Ltd. 2019 SCC 5*.

Regulated Emitters has the meaning set out in "*Industry Conditions – Climate Change Regulation – Alberta*".

Reserves Committee means the reserves committee of the Board.

Restricted Voting Shares means the additional class of shares, which shares are not entitled to vote with respect to the election of directors of Journey, that the Company created on June 6, 2014. See "*Description of Share Capital – Restricted Voting Shares*".

Senior Secured Credit Agreement means the Amended and Restated Senior Secured Credit Agreement between AIMCo and Journey entered into on October 30, 2020 and comprised of six tranches of term debt with an aggregate principal amount of $89,663,787.

SGER means the *Specified Gas Emitters Regulation* (Alberta).

Shareholders means the holders of Common Shares from time to time.

SSRP means the South Saskatchewan Regional Plan.

Sword means Sword Energy Inc.

Tax Act means the *Income Tax Act* (Canada), R.S.C. 1985, c-1 (5^{th} Supp.), as amended, including the regulations promulgated thereunder.

TSX means the Toronto Stock Exchange.

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

UNFCCC means the United Nations Framework Convention on Climate Change.

Updated Action Plan means an update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions".

Virginia means Virginia Hills Oil Corp.

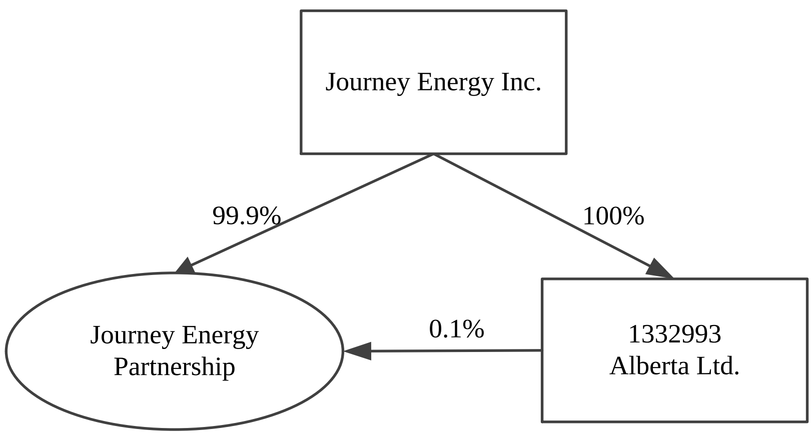
CORPORATE STRUCTURE

The Company was formed on June 26, 2007 under the ABCA as "Sword Energy Inc.". On July 1, 2012, Sword amalgamated with Capex Exploration Ltd. and 1685263 Alberta Ltd. Subsequent to this, Sword amalgamated with 1317139 Alberta Ltd. under the ABCA on the same day. The resulting entity amended its articles to change its name from Sword Energy Inc. to "Journey Energy Inc."

On May 7, 2014, Journey amended its articles to consolidate its Common Shares on a two for one basis. On June 6, 2014, the Company amended its articles to create the Restricted Voting Shares. See "*Description of Share Capital – Restricted Voting Shares*".

Journey's head office is located at Suite 700, 517 – 10th Avenue SW, Calgary, Alberta T2R 0A8 and its registered office is located at Suite 4000, 421 – 7th Avenue SW, Calgary, Alberta T2P 4K9.

The Company has two wholly-owned subsidiaries: Journey Energy Partnership, a general partnership formed under the laws of the Province of Alberta, and 1332993 Alberta Ltd., a corporation formed under the laws of the Province of Alberta.



GENERAL DEVELOPMENT OF THE BUSINESS

Recent Developments

In March of 2021 Journey announced its 2021 guidance. In its March 9, 2021 press release, Journey announced the intended course of action for 2021 is to spend capital only on maintenance capital and its planned decommissioning liability expenditures. The remaining cash flow will primarily go to repay term debt as well as enhance working capital. In addition, the Company announced that it had terminated its purchase and sale agreement for the disposition of its Countess, Alberta assets, which were comprised of a power generation asset as well as associated producing natural gas assets. Journey retained the deposit previously provided and continues to operate the assets.

Three Year History

2020

2020 will enter its place in history as a year with many challenges. During the first phase of the COVID-19 pandemic, the oil and gas industry experienced the largest single oil price decline in history. For Journey, there was no challenge more significant than dealing with its outstanding bank debt. The year started with strong commodity prices but by March, the world fell victim to the turmoil of the pandemic. In response to the decrease in crude oil prices, in April 2020, Journey reduced its capital budget to necessary maintenance capital on existing properties as well as completing the power generation project it started in the third quarter of 2019. The sharp decline in commodity prices put extraordinary stress on the reserve values that supported Journey's bank borrowings. Accordingly, the banks reduced the borrowing base and as a result Journey became drawn in excess of this new borrowing base level. Cash flows associated with these low commodity prices were insufficient for Journey to repay this deficiency. The Company spent the majority of 2020 in forbearance with its banking syndicate, trying to work out a solution that allowed the banks to exit, while providing the remaining stakeholders an opportunity to weather this devastating year.

These efforts culminated in a multi-party transaction on October 30, 2020, whereby Journey's largest shareholder and debt provider, AIMCo, loaned Journey $38 million to buy out the outstanding bank debt of $75 million. This restructuring was a milestone for Journey and represented the culmination of a substantial, collaborative effort from all parties. Journey successfully emerged from the state of forbearance and now has all of its borrowings held by AIMCo.

The Corporation incurred a large net loss in the first quarter of 2020 due primarily to a $60.9 million impairment charge which was triggered by the COVID-19 pandemic impact on anticipated future commodity prices due to supply and demand outlooks.

2019

The impact of the Government of Alberta imposed oil production curtailment was successful in lowering the historically high oil price differentials Alberta experienced in late 2018. WTI oil prices appreciated from a low of $51.55/bbl in January to a high of $63.87 in April. For the balance of the year WTI stayed in the $54-$60/bbl range. In addition, the WTI/Alberta oil differentials were fairly stable throughout the year to average $5.12/bbl USD. AECO spot natural gas prices performed well in the first quarter but the second and third quarters dropped below $1.00/gj CAD before rising to the mid-$2/gj level in the fourth quarter. Journey limited its capital spending in the year to 7 (7.0 net) wells in the Matziwin area. In addition, Journey started commissioning the acquisition and preliminary work on its power generation project in the Countess area. Journey will use its long-life, dry gas production in Countess to power two generators which will generate 4.0 mw of electricity. The start-up date for this project is anticipated to be the second quarter of 2020.

On September 30, 2019 all outstanding promissory notes issued to AIMCo were restructured into a single, second lien term debt financing comprised of two tranches. Before the restructuring, there were two sets of promissory notes issued, one from October of 2016 and the other from January of 2018. The Promissory Notes (2016) had a principal amount of $30 million and a maturity of October 31, 2020. These notes were restructured into a second lien tranche with a principal amount of $22 million with $8 million being repaid by Journey at closing. The maturity of this tranche was extended from the previous maturity date of October 31, 2020 to October 31, 2023 and the interest rate changed to 11.5% per annum from 7.65% per annum. New share purchase warrants of 1,331,617 were issued at an exercise price of $3.15 per warrant in consideration of the change in terms. The Promissory Notes (2018) had a principal amount of $22 million and an interest rate of 7.65% per annum with a maturity of September 30, 2023. No changes were made to the financial terms of this tranche. The warrants previously issued with the Promissory Notes (2018) were voluntarily surrendered by AIMCo for cancellation.

The Duvernay joint venture with Kiwetinohk Resources Corporation continued operations with the drilling of three wells, all of which were subsequently placed on-production during 2019. Performance of the wells continues to be in the top tier of wells drilled to date in the East Shale Basin. Journey shareholders will benefit from early development capital expenditures to be incurred by KRC, while Journey retains a 37.5% working interest in this commercial development.

2018

On January 31, 2018 Journey closed a $22,000,000 promissory note financing with AIMCo. The purpose of the financing was to provide the funds needed to purchase Journey shares from MIE. The Promissory Notes (2018) bear interest at the rate of 7.65% per annum with interest payable semi-annually. The Promissory Notes (2018) mature on September 30, 2022. In conjunction with the financing, AIMCo also received 2,310,000 warrants with an exercise price of $2.51 per warrant. Each warrant is exercisable into one Common Share and expire on June 1, 2020.

On February 2, 2018 Journey closed the purchase of 12,700,000 Common Shares from MIE for a purchase price of $1.68 per share. After the purchase, the shares were returned to treasury and cancelled. The aggregate purchase price of $21.3 million was financed with a $22 million term debt loan from AIMCo. The AIMCo debt bears interest at the rate of 7.65% per annum with semi-annual interest payments and will mature on September 30, 2022.

On August 29, 2018 Journey entered into a joint venture agreement to develop its East Duvernay shale oil undeveloped lands with Kiwetinohk Resources Corp. The Agreement contemplates both a two well "Commitment" phase followed by a five well "Option" phase as follows:

- For the two well Commitment phase, Kiwetinohk will pay 100% of the capital costs, and have 100% working interest, before payout of 58.33% of its costs to drill, complete, equip and tie in. Journey will be entitled to a 3.75% gross over-riding royalty on the production from the wells prior to payout. After payout, and conversion of the royalty, Kiwetinohk will have a 70.83% working interest in the commitment wellbores while Journey will have a 29.17% working interest. After earning, the working interests in the Commitment blocks, outside of the two commitment wells, will be Kiwetinohk 62.5% and Journey 37.5%. Kiwetinohk will be the operator of all of the lands earned.

- For the five well Option phase, Kiwetinohk will pay 100% of the capital costs, and have 100% working interest, before payout of 33.33% of its costs to drill, complete, equip and tie in. Journey will receive no royalty prior to payout. After payout, Kiwetinohk will have 70.83% working interest in the option wellbores while Journey will have a 29.17% working interest. After earning, the final working interests in the applicable earned Option block, outside of the five option wells, will be Kiwetinohk 62.5% and Journey 37.5%. Kiwetinohk will be the operator of all of the lands earned.

On October 1, 2018, operations under the joint venture were initiated. The first Commitment well was been drilled and cased to a measured depth of 6,500 meters. The 3,500 meter horizontal section represents one of the longest horizontal sections drilled in the East Duvernay shale basin to date. Operations on a second well from the same surface location were initiated on October 28.

During 2018 Journey experienced wide ranging oil prices as the theme for the year was rising WTI prices in the first nine months of the year, along with widening WTI/Edmonton Light oil differentials. In the last quarter of the year Journey rrealized prices decreased 38% to average $22.34/boe. This decline was led by the decrease in oil prices by 54% from the third quarter resulting from historic WTI/Canadian par differentials. Realized natural gas prices helped offset some of the negative oil price impact with a 48% increase from the third quarter and mainly attributable to the price diversification strategy Journey employed into the US markets. Due to the severe decline in oil prices, capital spending in the fourth quarter was dedicated to necessary maintenance expenditures only as Journey spent $1.1 million. Due to the uncertainty surrounding oil price direction, Journey did not drill any new wells in the fourth quarter. The Alberta Government imposed production restrictions on producers that became effective on January 1, 2019. Small producer such as Journey were not impacted by these curtailments, however, the differentials responded positively to this initiative late in December and shrank to $4/bbl from the $22/bbl experienced earlier in the month. As a result of no drilling activity in the fourth quarter production averaged 9,921 boe/d bringing the average for the year to 10,075 boe/d. Funds Flow for the fourth quarter were slightly negative at $42 thousand. This prompted management to defer any drilling plans into June of 2018 as we use Funds Flow from the early part of 2018 to reduce debt. Journey average less than $10/bbl CAD for oil prices in December of 2018.

DESCRIPTION OF THE BUSINESS

Journey is a Canadian exploration and production company focused on conventional, oil and natural gas operations in western Canada. Journey is a growth oriented company focused on drilling on its existing core lands, implementing water flood projects, executing on accretive acquisitions, growing its production base and developing a new oil resource play in the Duvernay. Management is focused on providing these returns by diligently managing its capital and by being disciplined in exploiting its extensive asset base. The Company's Common Shares trade on the TSX under the symbol "JOY".

Since the restructuring in July of 2012, Journey has grown its production from approximately 4,000 boe/d to approximately 8,000 boe/d by the end of 2020. This growth (which is net of non-core asset dispositions) has been achieved through a combination of successful drilling and strategic acquisitions. Management believes that Journey's existing asset base provides a robust inventory of organic drilling opportunities, which will support the Company's growth business model.

Journey's goals are to optimize its legacy oil pools on existing lands through the application of best practices in horizontal drilling and, where feasible, with water floods. Journey also intends to continue to grow the Company through strategic and accretive acquisitions to add drilling inventory and to manage production declines. Journey's long-term corporate strategy is to provide investors with a meaningful return profile through growth in net asset value and share price.

Journey's Properties

Journey operates in central and southern Alberta along a prolific resource fairway. Journey has a high working interest (approximately 85%) in its core properties, controls core area processing facilities, infrastructure egress and operatorship of its key oil pools, which pools have low current recovery factors. Journey estimates that there are over 300 oil pools along the fairway with drilling costs between approximately $1.5 to $3 million per well (including drilling, well completion, associated equipment and connecting to infrastructure costs). See "*Statement of Reserves Data – Disclosure of Reserves Data – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

In 2018 Journey accumulated over 100 sections of prospective East Duvernay shale lands. As of today this undeveloped land base has expanded to over 150 sections. Approximately 116 net sections are under development via a joint venture agreement with Kiwetinohk Resources Corporation.

Reorganizations

As at the date hereof, except as disclosed herein, there have been no material reorganizations of Journey and or any of its subsidiaries within the three most recently completed financial years and there are currently no material reorganizations of Journey proposed for the current financial year. See "*General Development of the Business*".

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against the Corporation or any of its subsidiaries or related entities, or any voluntary bankruptcy, receivership or similar proceeding by the Corporation or any of its subsidiaries or related entities since the inception of the Corporation or during or proposed for the current financial year.

Specialized Skill and Knowledge

Journey employs individuals with various professional skills in the course of pursuing its business plan. In addition, Journey has available to it various specialized consultants to assist it in areas where it does not need full time employees. These professional skills include, but are not limited to, geology, geophysics, engineering, finance and business development. Drawing on significant experience in the oil and natural gas business, Journey believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company, including: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Journey to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

The oil and natural gas industry is very competitive. Journey believes that it has a strong competitive position in the areas in which it operates. See "*Statement of Reserves Data – Disclosure of Reserves Data – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*". Journey's business strategy is to acquire and then develop legacy oil pools containing greater than 10 MMbbls each in central and southern Alberta. Journey then applies current horizontal drilling and water flood technology to these pools with the objective of growing production from these pools in order to exploit significant operating efficiencies in each core area. More recently, Journey has accumulated a significant land position in the East shale Duvernay. While much of Journey's land was acquired in private deals, by comparison Crown land purchases in this area have been very competitive with prices reaching as high as $2,500/ha.

Companies operating in the petroleum industry must manage risks, which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and Journey is required to compete with a substantial number of other entities, which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex.

Journey attempts to enhance its competitive position by operating in areas where it believes its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation. Management believes that Journey will be able to explore for and develop new production and reserves with the objective of increasing its cash flow and reserve base. See "*Risk Factors – Competition*".

Cycles

The Company's business is often driven by weather conditions and the health of the economy. Demand for oil and gas rises and falls with the strength of the economy as well as with the cold in the winters and the heat in the summers. This occurs both on a continental as well as a global level. A strong economy creates higher prices, which in turn produces more capital that the Company can expend on its capital program. A weak economy has the opposite effect. Cold winters and hot summers produce extra demand for natural gas on a continental basis, which in turn increases natural gas prices. In addition, the exploration for and the development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including "freeze-up" and "break-up", affect access in certain circumstances. See "*Risk Factors – Seasonality*".

Environmental Protection

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 might have a significant negative impact on earnings and overall competitiveness of the Company. For a description of the financial and operational effects of environmental protection requirements on the capital expenditures, earnings and competitive position of Journey, see "*Risk Factors – Environmental*".

Employees

As at December 31, 2020, Journey had 32 full-time employees located at its head office in Calgary and 8 full-time employees located in the field. In addition, Journey had 30 contract operators in various field locations.

Environmental, Health and Safety Policies

The Company supports and promotes environmental protection and employee health and safety through the implementation and communication of the Company’s environmental management and employee occupational health and safety programs, policies and procedures. These programs, policies and procedures are designed to allow for employee participation and development for continuous improvement and to provide employees with job orientation, training, instruction and supervision to assist them in conducting their activities in an environmentally responsible and safe manner.

The Company develops emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities in which it operates in order to effectively respond to an environmental incident should it arise. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks and operational exposures. The Company conducts audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed.

The Company also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. The Company’s environmental and occupational health and safety management systems are designed to manage such risks in the Company’s business and allow action to be taken to mitigate the extent of any environmental, health or safety impacts from such operations.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments in the jurisdictions where the companies have assets or operations. While such regulations do not affect the Corporation'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 regulations carefully. Although laws and regulations are a matter of public record, the Corporation is unable to predict what additional laws, regulations or amendments governments may enact in the future.

The Corporation holds interests in crude oil and natural gas properties, along with related assets, primarily in the Canadian province of Alberta. The Corporation's assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of the Corporation's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time-to-time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments governments may enact in the future.

Outlined below are some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Western Canada, specifically in the province of Alberta, where the Corporation's assets are primarily located. While these matters do not affect the Corporation'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 matters carefully.

Pricing and Marketing

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; however, regional market and transportation issues also influence prices. The specific price depends, 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.

Since early 2020, worldwide oversupply of oil, a lack of available storage capacity and decreased demand due to COVID-19 have had a significant impact on the price of oil. In an effort to stabilize global oil markets, the OPEC and a number of other oil producing countries announced an agreement to cut oil production by approximately 10 million bbls/d in April 2020. This agreement contributed to rebalancing global oil markets by achieving approximately 99.5% compliance with the agreed production adjustment commitments. However, economic recovery has slowed due to a resurgence of COVID-19 and newly emerging virus variants in major economies.

Natural Gas

Canada's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years, or for a term of two to 20 years (in quantities of not more than 30,000 m3 per day), must be made pursuant to an NEB order. Exporters are required to obtain an export license from the NEB for natural gas export contracts of a longer duration (to a maximum of 40 years), or that deal with terms of greater than two years and quantities of natural gas greater than 30,000 m3 per day.

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane 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.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the *National Energy Board Act* (the "**NEB Act**") with the *Canadian Energy Regulator Act* (Canada) (the "**CERA**"), and replacing the National Energy Board (the "**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime.

Exports of crude 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**"). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. For natural gas, the maximum duration of an export licence is 40 years; for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. To obtain a crude oil export licence, a mandatory public hearing with the CER is required; however, there is no public hearing requirement for the export of natural gas and NGLs. Instead, the CER will continue to apply the NEB's written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes are not greater than Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CERA and all associated regulations and orders made under the CERA. Following the CER's approval of an export licence, the federal Minister of Natural Resources is mandated to give his or her final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government ("**Cabinet**") is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect "oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment".

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m3 per day.

As to price, 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. The Corporation does not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

One major constraint to the export of oil, natural gas and NGLs is the deficit of transportation capacity to transport production from Western Canada to other parts of Canada, the United States and other international markets. Although certain pipeline and other transportation and export projects 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 over the last several years.

Pipelines - general

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

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. The federal government amended the federal approval process with the CER, which aims to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved at a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty may result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate.

Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals from several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets 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.

Specific Pipeline Updates

The Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, has faced significant delays due to permitting difficulties in the United States. However, Minnesota regulators approved the final required permit for the project in November 2020. Certain segments of the Line 3 Replacement in North Dakota and Wisconsin are currently in operation and the Canadian portion of the replaced pipeline began commercial operation in December 2019. Construction of the Line 3 Replacement in Minnesota began in early December 2020; Enbridge expects the line to be in service in the fourth quarter of 2021.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019 and it is expected to be in-service in December 2022.

On March 31, 2020, TC Energy Corporation ("**TC Energy**") announced it would proceed with the Keystone XL Pipeline. TC Energy also announced that the Government of Alberta had made a US $1.1 billion equity investment in the project and would guarantee a US $4.2 billion project level credit facility. While construction on the Keystone XL

Pipeline started in April 2020, the project remains subject to legal and regulatory barriers in the United States, including the cancellation of a presidential permit on January 20, 2021 that permits the Keystone XL Pipeline to operate across the international border.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, potentially forcing the lines comprising this segment of the pipeline system to be shut down by May 2021. Enbridge filed a federal complaint in late November 2020 in the Unites States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge stated in January 2021 that it intends to defy the shutdown order, as the dual pipelines are in full compliance with U.S. federal safety standards.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been restricted access to storage. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline system (the "**NGTL System**") to prioritize deliveries into storage. The change stabilized supply and pricing, particularly during periods of maintenance on the system. TC Energy received Government of Canada approval for an expansion to the NGTL System in October 2020, with pipeline construction activities expected to begin in January 2021 and a target in-service date of April 2022. The CER has started a process to determine whether it will extend the temporary service protocol. Final arguments took place in late January 2021.

Marine Tankers

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

Crude Oil and Bitumen by Rail

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020 that trains hauling more than 20 cars carrying dangerous goods, including oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in April 2020 and replaced in November 2020. The speed limits and other requirements established in the November 2020 order will remain in place until permanent rule changes are approved.

Natural Gas

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 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 generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network (which carries much of Alberta’s gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. January 2020 has seen the narrowest price differential between Canadian and United States Natural Gas benchmarks since early 2019.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, government decision-making, regulatory 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 proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project. Pre-construction activities began in November 2018, with a planned completion target of 2025. In late 2019, TC Energy announced that it would sell a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction closed in May 2020. Despite its approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding.

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Oil and Gas Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of a LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd., would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Enbridge Open Season

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided to shut down the open season. On December 19, 2019, Enbridge applied to the CER for approval of the proposed service and tolling framework. The regulatory hearing process is currently underway and a final decision from the CER is not expected until mid-2021. If Enbridge receives CER approval, it intends to hold the open season by the end of 2021.

Curtailment

In December 2018, the Government of Alberta announced that it would mandate a short-term and temporary curtailment of provincial oil and bitumen production. Curtailment first took effect on January 1, 2019. As contemplated in the *Curtailment Rules*, the Government of Alberta, on a monthly basis, required oil and bitumen producers producing more than 20,000 bbls/d to limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

As of December 2020, monthly oil production limits are no longer in effect. However, the *Curtailment Rules*, which were set to be repealed on December 31, 2020, have been extended such that the Government of Alberta retains the ability to impose production limits if needed.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/USMCA

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement, the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**NAFTA**") on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the implementation of the USMCA could have an impact on Western Canada's oil and 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 eastern Canada, Asia and Europe.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world. 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 Comprehensive Economic and Trade Agreement ("CETA"), which provides for duty- free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA remains subject to ratification by 14 of the 28 national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union. As such, CETA will remain in place until December 31, 2020.

Canada and ten other countries have agreed on the text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("CPTPP"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among the first seven countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, Vietnam, and Singapore.

While it is uncertain what effect CETA, CPTPP, or any other trade agreements will have on the crude 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.

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 a significant factor in the profitability of crude 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 mineral freehold 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 governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum substance produced.

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

In addition, the federal government may from time-to-time provide incentives to the oil and natural gas industry. In November of 2018, the federal government announced its plans to implement an accelerated investment incentive, aimed to provide oil and natural gas businesses with eligible Canadian development expenses ("**CDE**") and Canadian oil and gas property expenses ("**COGPE**") with a first year deduction of one and a half times the deduction that is otherwise available for CDE. The definitions of "accelerated CDE" and "accelerated COGPE", as amended in November 2018, allow oil and natural gas businesses to claim an additional 15% deduction for new CDE, and an additional 5% deduction for new COGPE for taxation years that end before 2024, if such CDE or COGPE was incurred after November 20, 2018. The acceleration is reduced to 7.5% for new CDE and 2.5% for new COGPE for taxation years that begin after 2023 and end before 2028. Successored expenses, and costs in respect of Canadian resource properties not acquired at arms' length, will not qualify for treatment as accelerated CDE or accelerated COGPE.

The federal government also announced in late 2018 that it would make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada. Export Development Canada has lent or guaranteed $629 million among 37 companies, of $1 billion available to oil and natural gas producers. The Bank of Canada has made 892 loans totaling $207.5 million out of its $500-million commercial loan allotment in the aid package. Innovation, Science and Economic Development Canada announced $49 million each for two projects to help Alberta companies building facilities to turn propane into polypropylene, a type of plastic not currently produced in Canada, but often used in packaging and labels. Natural Resources Canada distributed $37 million of a $50-million commitment under its Clean Growth Program for nine projects that help oil and natural gas companies reduce their carbon footprints.

Producers and working interest owners of crude oil and natural gas rights may also carve out 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.

Alberta

In Alberta, the provincial government royalty rates apply to Crown-owned mineral rights. In Alberta, 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* 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, Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2019 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue minus costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator (the "**AER**") on an annual basis. Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of 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. 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 towards a minimum 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 and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout. The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2019 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. 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 metres 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. Currently, producers of crude oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

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 coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells. Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production.

Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in Alberta is included in the above description of the royalty regimes in Alberta.

Where oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and natural gas agreements between Indigenous groups and producers, and collecting and distributing royalty revenues. The exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific Indigenous group. Ultimately, the relevant Indigenous group must approve the royalty rate for each lease.

Land Tenure

The respective provincial governments (i.e. the Crown), predominantly own the mineral rights to 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. The 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. To develop crude oil and natural gas resources, it is necessary for the mineral estate 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 for affected persons for lost land use and surface damage. Alberta has 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. Additionally, Alberta has shallow rights reversion for shallow, non-productive geological formations for new leases and licences. 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 the province of Alberta. According to Alberta Energy, approximately 19% of mineral rights in the Province of Alberta are owned by private freehold owners and other non-Crown entities. Rights to explore for and produce such 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 crude oil and natural gas explorers and producers. 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 the applicable indigenous peoples, for exploration and production of crude oil and natural gas on indigenous reservations.

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 manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations. Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995*. In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"); however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019 and further regulations are currently being developed. The Corporation does not have operations on Indian reserve lands.

Surface rights

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. 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, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

General

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

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 *Impact Assessment Act* (the "**IAA**") replaced the *Canadian Environmental Assessment Act, 2012*. 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. 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. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. 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 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 from the CER and the IAA. 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. It also requires an expanded public interest assessment. Designated projects specific to the oil and gas industry include pipelines that require more than 75km 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 and the hearing is expected to take place in the first half of 2021.

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* and a number of related statutes including the *Oil and Gas Conservation Act* (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 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, earthquakes 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 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 oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2*, *6*, and *7*. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**"). The Corporation does not have operations in Seismic Protocol Regions.

Liability Management Rating Programs

Alberta

The AER administers the licensee Liability Management Rating Program (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). At its core, the AER uses the AB LMR Program to aid in determining the ability of licensees to manage the abandonment and reclamation obligations associated with the licensee's assets. If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licenses. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**"). The AER assesses the LMR of all licensees on a monthly basis and posts the ratings on the AER's public website. Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

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

In response to the increase in orphaned oil and gas sites and the environmental risks associated therewith, the AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that they can meet their abandonment and reclamation obligations, such as by posting security or reducing their existing obligations.

As a result of the Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "**Redwater**" decision), receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a licence transfer when any such licensee 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 *Liabilities Management Statutes Amendment Act*, which places the burden of a defunct licensee's abandonment and reclamation obligations first on the defunct licensee'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. These changes will come into force on proclamation.

Additionally, the Government of Alberta announced in July 2020 that the AB LMF will replace the AB LMR Program and its constituent programs. Among other changes under the AB LMF, the AB LMR Program will be replaced with the Licensee Capability Assessment System, 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 LMR Program and establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of oil and gas projects. Importantly, the AB LMF will also provide proactive support to distressed operators and will require mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets.

The Government of Alberta followed the announcement of the AB LMF with amendments to the *Oil and Gas Conservation Rules* and the *Pipeline Rules* in late 2020. The changes to these rules fall into three broad categories: (i) they introduce "closure" as a defined term, which captures both abandonment and reclamation; (ii) they expand the AER's authority to initiate and supervise closure; and (iii) they permit qualifying third parties on whose property wells or facilities are located to request that licensees prepare a closure plan.

The AER has published a draft of an amended Directive 067 to implement some of these changes (the "**Draft Directive**"), and has issued a call for feedback on the Draft Directive that will be open until mid-February 2021. The changes introduced by the Draft Directive include building on the AER's corporate and financial disclosure requirements for parties who wish to acquire, hold or transfer licences in Alberta, and broadening the AER's discretion to withhold or revoke licensees' privileges if they are assessed as posing an "unreasonable risk". The feedback that the AER receives will be considered in the determination of the final revised Directive 067, and the rollout of the AB LMF may require changes to other Directives as well. As a result, the Corporation's ongoing and future transactions may be affected in this period of transition, resulting in processing delays for licence transfers and regulatory uncertainty as the criteria and requirements for licensees are subject to change.

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

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's oil and gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its $1 billion share of the federally provided funds through the Site Rehabilitation Program. In addition to the funds administered by the respective provincial governments, the federal government announced a $200 million loan to Alberta's Orphan Fund.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future of the crude oil and natural gas industry in Canada. The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (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. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. Decisions about a prospective carbon market and emissions cuts have been delayed until the next climate conference, which is scheduled to take place in November 2021.

The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030, but indicated in its recent Speech from the Throne (also referred to as the "**Throne Speech**"; discussed in greater detail below) that it may implement policy changes to exceed this target. Specific details have not yet been announced.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of carbon dioxide equivalent ("**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. This ensures that there is a uniform price on emissions across the country. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne of CO2e in 2022. On December 11, 2020, however, the federal government announced its intention to continue the annual price increases beyond 2022, such that, commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Starting April 1, 2021, the minimum price permissible under the GGPPA is $40/tonne of CO2e. Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In the Saskatchewan and Ontario references, the appellate Courts found the GGPPA to be constitutional; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments have been appealed to the Supreme Court of Canada. The hearing took place in September 2020, but the Court has not yet released its decision.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the oil and natural gas sector, 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 and ensure that 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.

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

As part of its efforts to provide relief to Canada's oil and gas industry in light of the COVID-19 pandemic, the federal government announced a $750 million Emissions Reduction Fund intended to support pollution reduction initiatives, including methane. Funds disbursed through this program will primarily take the form of repayable contributions to onshore and offshore oil and gas firms.

The federal government has also announced that it will implement a Clean Fuel Standard that will require producers, importers and distributors to reduce the emissions intensity of liquid fuels. It is expected that the applicable regulations will come into force in December 2022.

In the September 23, 2020 Throne Speech, the federal government has indicated that it intends to make a number of investments that will help it achieve net-zero emissions by 2050, including investments intended to: (i) improve transit options; (ii) make zero-emissions vehicles more affordable; (iii) expand electric vehicle charging infrastructure across the country; (iv) launch a fund that will help attract investments in the development of zero-emissions technology, including a corporate tax cut of 50% for companies participating in this initiative; (v) develop a Clean Power Fund that will, in part, help regions transition to cleaner sources of power generation; and (vi) support continued investment in the development and implementation of renewable and clean energy technologies. Specific program details have not yet been announced.

On November 19, 2020, the federal government introduced the *Canadian Net-Zero Emissions Accountability Act* in Parliament. If passed, this Act will bind the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It will also establish rolling five-year emissions-reduction targets and require the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body and require the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of climate change in their decision-making.

Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* (the "**CLA**") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The Carbon Competitiveness Incentives Regime ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this will increase to $30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed Technology Innovation and Emissions Reduction ("**TIER**") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020. The TIER regulation operates differently than the former facility-based CCIR, and instead applies industry-wide 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 (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas- fired generation system. 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. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. 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.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") 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 Directives will support Alberta in achieving its 2025 goal. In November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

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 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.

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 income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

RISK FACTORS

Following is a list of risks that the Company faces in its normal course of business. 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.

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

Liquidity and Additional Funding Requirements

On October 30, 2020, Journey secured a $38 million term-debt facility from its largest shareholder, AIMCo, to fund the settlement of its then outstanding $75 million of bank borrowings with its syndicate of first-lien lenders. In addition to the initial $38 million payment to the banking syndicate, Journey will also be contingently liable to pay the former banking syndicate a maximum of $5.75 million over a three year period with the level of payment made tied to various levels of mixed, sweet, blended oil prices at the Edmonton, Alberta hub (“MSW”) as reported by Natural Resources

Canada. The payment for the 2021 determination year is capped at $750 thousand; 2022 is capped at $2.25 million; and for 2023 the payment is capped to the aggregate total of $5.75 million.

The $38 million secured term debt facility was provided by AIMCo in three tranches. The first tranche is for $15 million and bears interest at 11.5% per annum and through a series of amendments now matures on June 30, 2021. On March 2, 2021 Journey made a partial payment on this tranche of term debt in the amount of $3.75 million. The second tranche is for $10 million, matures October 31, 2021 and bears interest at 9.0% per annum. The third tranche is for a principal amount of $13 million, matures October 31, 2024, and bears interest of 9.0% in year one, 9.85% in year two and 12.95% in years three and four. In connection with the term debt advances Journey issued 5.0 million share-purchase warrants to AIMCo. The warrants entitle the holder to purchase one common share of Journey at an exercise price of $0.16 per warrant, which reflects a 25% premium to the 10 day weighted average trading price of Journey common shares leading up to October 30. The warrants have a four year term and expire in October 30, 2024. In addition, a commitment fee loan of $5.35 million is payable to AIMCo on October 30, 2024 and bears interest at rates which are dependent upon specified ranges of Edmonton mixed sweet oil prices. Below $65/bbl it bears interest at zero percent per annum, if prices are between $65/bbl and $80/bbl it bears interest at 5.0% per annum and if MSW prices exceed $80/bbl it bears interest at 10.0% per annum.

While the Company has concluded substantial efforts to improve its overall debt position in 2020, there still remains uncertainties, which are being primarily caused by the ongoing Covid-19 Pandemic (see *Risk Factors "Impact of Pandemics*")) with respect to commodity prices. This in turn can have a negative impact on Journey's ability to repay its maturing term debt in 2021 and could cast doubt as to the Company's ability to continue as a going concern. The recent improvement in commodity prices has been positive in improving the outlook for the Company's liquidity, however, with the inability of the purchaser to close the previously announced Countess asset disposition on March 1, 2021 there remains uncertainty over the Company's ability to repay AIMCo the two term debt tranches totalling $21.25 million (after the $3.75 million repayment made on March 2, 2021) that are due in 2021. AIMCo is the single largest shareholder and the sole debt holder in Journey and the Company continues to explore an amicable solution to the maturities.

Journey's funds flow from its reserves or funds available under its current Credit Facility may not be sufficient to fund its ongoing activities at all times, and from time to time, it may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Company's access to additional financing may be affected.

Due to significant uncertainty in the credit markets, Journey may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect its ability to expend 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 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 affected materially and adversely as a result. In addition, the future development of the Company's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for Journey's capital expenditure plans may result in a delay in development or production on its properties.

Prices, Markets and Marketing

Numerous factors beyond Journey's control do, and will continue to affect the marketability and price of oil and natural gas acquired or discovered by it. Journey's ability to market its oil and natural gas may depend upon the ability to acquire space on pipelines that deliver natural gas to commercial markets. Deliverability uncertainties related to the distance of Journey's reserves to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Company.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the Company's control. These factors include economic conditions in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale production in the United States, the decline in global demand for exported crude commodities, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. 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 or 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. In addition, lower commodity prices caused the Company to spend minimal capital in 2020. The capital that was spent during the year was concentrated on strategic assets that contribute to the Company's cost-reduction and revenue diversification strategies.

North American crude oil price differentials are expected to continue to be volatile in 2021. This will have an impact on crude oil prices for Canadian producers. Although opportunities to move oil by rail continue to grow and will provide new outlets for access to North American refineries otherwise not reachable via existing pipeline infrastructure, supply in excess of current pipeline and refining capacity is expected to continue to exist. Material structural changes are required to reduce these bottlenecks and the resulting steep price discounts. A variety of new pipeline expansion projects to provide increased access to eastern Canadian and Gulf Coast refineries, as well as new off-shore markets, have been announced and are in various stages of review and approval. There can be no assurance that such regulatory approvals will be secured on a timely basis or at all.

All these factors could result in a material decrease in Journey'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 and natural gas would have an adverse effect on the carrying value of Journey's reserves, borrowing capacity, revenues, profitability and funds flow and may have a material adverse effect on its business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, and sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile 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 oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the ongoing COVID-19 pandemic, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation'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 or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Risk Factors – General Weakness and Volatility in the Oil and Gas Industry*".

Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. See "*Risk Factors – Senior Secured Credit Agreement*".

In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement.

General Weakness and Volatility in the Oil and Gas Industry

Market events and conditions, including global excess oil and natural gas supply, the ongoing COVID-19 pandemic, recent actions taken by the OPEC, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakened global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including a growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. See "*Risk Factors – Political Uncertainty*" and "*Risk Factors – Impact of Pandemics*". These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Industry Conditions – Royalties and Incentives*", "*Industry Conditions – Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*". In addition, the difficulties encountered by midstream proponents to obtain on a timely basis or continue to maintain the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year-over- year basis. See "*Risk Factors – Reserves Estimates*". Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. See "*Risk Factors – Senior Secured Credit Agreement*". In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. See "*Risk Factors – Liquidity and Additional Funding Requirements*".

Impact of Pandemics

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide, including COVID-19, Middle East Respiratory Syndrome, Severe Acute Respiratory Syndrome, H1N1 influenza virus, avian flu or any other similar illnesses could have an adverse impact on the Corporation's results, business, financial condition or liquidity.

On March 11, 2020, the World Health Organization declared the outbreak of a strain of novel coronavirus disease, COVID- 19, a global pandemic. The COVID-19 pandemic has negatively impacted the Canadian, U.S., and global economies; disrupted Canadian, U.S., and global supply chains; disrupted financial markets; contributed to a decrease in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the U.S., and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. Unexpected developments in financial markets, regulatory environments, or consumer behaviour may also have adverse impacts on the Corporation's results, business, financial condition or liquidity, for a substantial period of time.

The Corporation's business, financial condition, results of operations, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans may, in particular, and without limitation, be adversely impacted as a result of the pandemic and/or decline in commodity prices as a result of:

- the shut-down of facilities or the delay or suspension of work on major capital projects due to workforce disruption or labour shortages caused by workers becoming infected with COVID-19, or government or health authority mandated restrictions on travel by workers or closure of facilities or worksites;
- suppliers and third-party vendors experiencing similar workforce disruption or being ordered to cease operations;
- reduced cash flows resulting in less funds from operations being available to fund capital expenditure budgets;
- reduced commodity prices resulting in a reduction in the volumes and value of reserves;
- storage constraints for crude oil, natural gas and other produced or processed products resulting in the curtailment or shutting in of production;
- counterparties being unable to fulfill their contractual obligations on a timely basis or at all;
- the inability to deliver products to customers or otherwise get products to market caused by border restrictions, road or port closures or pipeline shut-ins, including as a result of pipeline companies suffering workforce disruptions or otherwise being unable to continue to operate; and
- the ability to obtain additional capital including, but not limited to, debt and equity financing being adversely impacted as a result of unpredictable financial markets, commodity prices and/or a change in market fundamentals.

The COVID-19 pandemic has also created additional operational risks for the Corporation, including the need to provide enhanced safety measures for its employees and customers; comply with rapidly changing regulatory guidance; address the risk of, attempted fraudulent activity and cybersecurity threat behaviour; and protect the integrity and functionality of the Corporation's systems, networks, and data as a larger number of employees work remotely. The Corporation is also exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures implemented in response to the COVID-19 pandemic, as well as the potential for a significant proportion of the Corporation's employees, including key executives, to be unable to work effectively, because of illness, quarantines, sheltering- in-place arrangements, government actions or other restrictions in connection with the pandemic.

The extent to which the COVID-19 pandemic continues to impact the Corporation's results, business, financial condition or liquidity will depend on future developments in Canada, the U.S. and globally, including the development and widespread availability of efficient and accurate testing options, and effective treatment options or vaccines. Despite the approval of certain vaccines by the regulatory bodies in Canada and the U.S., the ongoing evolution of the development and distribution of an effective vaccine also continues to raise uncertainty.

Political Uncertainty

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 Trans-Pacific Partnership 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. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the USMCA which will replace NAFTA once ratified by the three signatory countries. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. In January 2020, the Canadian Parliament tabled Bill C-4 which, once proclaimed into force will ratify the USMCA. The USMCA is expected to fully replace NAFTA two months after Bill C-4 comes into force. See "*Industry Conditions - The North American Free Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the

The newly-inaugurated Biden administration in the U.S. has indicated that it will roll-back certain policies of the former administration, and has taken action to cancel TC Energy Corporation's Keystone X.L. pipeline permit. While it is unclear which other legislation or policies of the former Trump administration will be rolled-back and if such roll-backs will be a priority of the new administration in light of the ongoing COVID-19 pandemic, any future actions taken by the new U.S. administration could have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined. 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, it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of the common shares.

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 oil 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. Though the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia. In January 2020, tensions and disputes remain high between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction

The federal Government was re-elected in 2019, but 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 oil 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 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 oil and natural gas industry. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Transportation Constraints and Market Access*", "*Industry Conditions – Curtailment*" and "*Industry Conditions – The North American Free Trade Agreement and Other Trade Agreements*". The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Corporation's activities. See "*Industry Conditions – Transportation Constraints and Market Access – Natural Gas*".

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. However, in early 2020, the Supreme Court of Canada and the Federal Court of Appeal both dismissed challenges to cabinet's approval of the Trans Mountain Pipeline expansion, and construction on the pipeline expansion is underway. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on interprovincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in the Corporation's inability to realize the full economic potential of its products or in a reduction of the price offered for the Corporation's production. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the CERA and the IAA came into force and the *National Energy Board Act* and the CERA, 2012 were repealed. In addition, the Impact Assessment Agency of Canada replaced the Canadian Environmental Assessment Agency. See "*Industry Conditions – Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the Corporation's ability to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment, which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Exploration, Development and Production Risks

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

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

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, and spills or other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company.

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

As is standard industry practice, the Company is not fully insured against all risks, nor are all risks insurable. Although the Company maintains liability insurance in an amount the Company considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Company could incur significant costs.

Delays in Business Operations

Delays in business operations could adversely affect dividends to Shareholders and the market price of the Common Shares. In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of Journey's properties and the delays of those operators in remitting payment to Journey, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- restrictions due to limited pipeline capacity;
- blowouts or other accidents;
- accounting delays;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could expose Journey to additional third party credit risks.

Reliance on Groundwater

Journey relies on 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 license 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 a fee for the use of water in the future or that any such fees will be reasonable. 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.

Project Risks

Journey manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Journey’s ability to execute projects and market oil and natural gas depends 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 availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Company’s ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled 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 could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that it produces effectively.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market, including governmental regulatory actions or adverse changes in general market conditions or economic trends. In certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors, as well as the Company's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, acquisitions, dispositions or other material public announcements by the Company or its competitors, along with a variety of additional factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Impact of Future Financings on Market Price

In order to finance future operations or acquisition opportunities, the Corporation may raise funds through the issuance of Common Shares or the issuance of debt instruments or securities convertible into Common Shares. The Corporation cannot predict the size of future issuances of Common Shares or the issuance of debt instruments or other securities convertible into Common Shares or the effect, if any, that future issuances and sales of the Corporation's securities will have on the market price of the Common Shares.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive to Shareholders.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (exploration, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase Journey's costs, either of which may have a material adverse effect on Journey's business, financial condition, results of operations and prospects.

In order to conduct oil and natural gas operations, Journey requires licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, Journey's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact the Corporation's operations, which may affect the Corporation's profitability. See "*Industry Conditions – Environmental Regulation*". Also, in response to widening pricing differentials, the Government of Alberta implemented production curtailment. See "*Industry Conditions – Curtailment"* and "*Risk Factors – Liability Management*". In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See "*Industry Conditions – Environmental Regulation and Liability Management Rating Programs*".

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 obligation. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes to the required ratio of the Company's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Company's compliance requirement. In addition, the liability management system may prevent or interfere with the Company's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and 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.

Forward-Looking Information

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumption and uncertainties are found under "*Forward-Looking Statements*".

Substantial Capital Requirements

Journey anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, Journey’s ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- its credit rating (if applicable);
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and its securities, in particular.

Further, if Journey’s revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. Journey’s inability to access sufficient capital for its operations could have a material adverse effect on its business, financial condition, results of operations and prospects.

Senior Secured Credit Agreement

The Company has a term debt credit agreement with AIMCo. AIMCo is currently the sole lender to Journey as of October 30, 2020. The Company is required to comply with covenants under its credit facility, which may affect the availability, or price, of additional funding and, in the event that the Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with covenants could result in default under the credit agreement, which could result in the Company being required to repay amounts owing thereunder. In addition, the credit agreement may impose operating and financial restrictions on the Company that could include restrictions on, the payment of dividends, repurchasing or making other distributions with respect to the Company's securities, incurring additional indebtedness, providing guarantees, the assumption of loans, making capital expenditures, entering into amalgamations, mergers, take-over bids or disposing of assets, among others.

The Supreme Court of Canada's decision in Redwater may give rise to new covenants and restrictions under the Corporation's credit agreement, should LMR levels fall below existing agreed-upon thresholds, including further limitations on asset dispositions and acquisitions. The Corporation may also be required to provide additional reporting to its lenders regarding its existing and/or budgeted abandonment and reclamation obligations, its decommissioning expenses, its LMR and/or any notices or orders received from an energy regulator in any applicable province. The Corporation's lenders may also put Journey into default under the credit facility following a decline in its LMR below a certain threshold or if the Corporation becomes subject to an abandonment and reclamation order and its estimated cost of compliance with such order exceeds a certain threshold. See also "*Industry Conditions – Liability Management Rating Programs*".

If the Company's lenders require repayment of all or a portion of the amounts outstanding under its credit agreement for any reason, including a default of a covenant, there is no certainty that the Company would be in a position to make such repayment. Even if the Company is able to obtain new financing in order to make any required repayment under its credit facilities, it may not be on commercially reasonable terms or terms that are acceptable to the Company. If the Company is unable to repay amounts owing under credit facilities, the lenders under the credit facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this AIF are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil, natural gas and NGL’s;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. Journey’s actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, the Company's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from Journey's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and thus does not reflect changes in Journey's reserves since that date.

Management of Growth

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

Reliance on Key Personnel

Journey's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the business, financial condition, results of operations and prospects. The Company does not have any key person insurance in effect. The contributions of the existing management team to its immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that Journey will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of Journey's management. In addition, certain of the Corporation's current employees are senior and have significant knowledge that must be transferred to other employees prior to their departure from the workforce. If the Corporation 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 Corporation could be negatively impacted. In addition, the Corporation could experience increased costs to retain and recruit these professionals

Operational Dependence

Other companies operate some of the assets in which Journey has an interest. The Company has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the financial performance. Journey's return on assets operated by others depends upon a number of factors that may be outside of the Company's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Company has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Company has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, the Company may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Company potentially becoming subject to additional liabilities relating to such assets and the Company having difficulty collecting revenue due from such operators or recovering amounts owing to the Company from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse effect on the Company's financial and operational results.

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new or modify the royalty regime which may have an impact on the economics of Journey's projects. An increase in royalties would reduce the Company's earnings and could make future capital investments, or its operations, less economic.

Environmental

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

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the suspension or revocation of regulatory permits, damage claims and the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it is in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the business, financial condition, results of operations and prospects of Journey.

Disposal of Fluids Used in Operations

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Corporation's costs of compliance.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Environmental Regulation – Federal*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Company's operating expenses, each of which may have a material adverse effect on the Company's profitability and financial condition. Further, the imposition of carbon taxes puts the Company at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Issuance of Debt

From time to time, Journey may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of a similar size. Depending on future exploration and development plans, Journey may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that it may incur. The level of Journey's aggregate indebtedness from time to time could impair its ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

Journey has implemented a hedging policy using, amongst others, collars and fixed price swaps to hedge a maximum of 50% of its gross oil, NGL and natural gas forecast volumes, respectively, for the following 24 months. In addition, the policy indicates that the product being hedged be as close as possible to the quality and type of products, which Journey produces. These hedging activities could expose the Company to losses or gains. To the extent that Journey engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose Journey to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time, Journey may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, Journey will not benefit from the fluctuating exchange rate.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat Journey's claim. The Company's actual interest in properties may, therefore, vary from its records. If a title defect does exist, it is possible that Journey may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on its business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties that Journey controls that, if successful or made into law, could impair Journey's activities and result in a reduction of the revenue received by Journey.

Expiration of Licences and Leases

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

Income Taxes

Journey has filed all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. Notwithstanding this, such 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 Journey. In the event of a successful reassessment, Journey may be subject to higher than expected past or future income tax liability as well as potential interest and penalties.

Income tax laws, including those laws applicable to the oil and gas industry, and government incentive programs relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects Journey. 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. Due to Journey’s un-deducted tax pool position, the Company does not believe it will pay any current income tax at least the next five years.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

Journey considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company may realize less on disposition than their carrying value on the financial statements of the Company.

In addition, acquisitions of oil and gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquiror, independent engineers and consultants. These assessments include a series 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 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 Company. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated. Although select title and environmental reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat the Company's title to certain assets or that environmental defects, liabilities or deficiencies do not exist or are greater than anticipated. Such deficiencies or defects could adversely affect the value of the assets acquired and the Company's securities.

Forward Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Company's forward-looking information and, in particular, the guidance provided under "*General Development of the Business – Recent Developments*". By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumption and uncertainties are found under "*Forward-Looking Statements*".

Competition

The petroleum industry is competitive in all its phases. Journey competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Journey's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than the Company's. Journey's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/U.S. dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar negatively affect the Company's production revenues. Future Canadian/United States exchange rates could accordingly affect the future value of the Company's reserves as determined by independent evaluators.

To the extent that Journey engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which it may contract. An increase in interest rates could result in a significant increase in the amount that Journey pays to service debt, resulting in a reduced amount available to fund its exploration and development activities and, if applicable, the cash available for dividends and could negatively impact the market price of its Common Shares.

Changing Investor Sentiment

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

Reputational Risk Associated with the Corporation's Operations

The Corporation's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Corporation or as a result of any negative sentiment toward, or in respect of, the Corporation's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Corporation operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. The Corporation's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Corporation has no control. Similarly, the Corporation's reputation could be impacted by negative publicity related to loss of life, injury or damage to property and environmental damage caused by the Corporation's operations. In addition, if the Corporation develops a reputation of having an unsafe work site it may impact the ability of the Corporation to attract and retain the necessary skilled employees and consultants to operate its business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and fossil fuel companies may impact the Corporation's reputation. See "*Risk Factors – Climate Change*". Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard the Corporation's reputation. Damage to the Corporation's reputation could result in negative investor sentiment towards the Corporation, which may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Corporation's securities.

Litigation

In the normal course of Journey'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, land 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 Journey and as a result, could have a material adverse effect on its assets, liabilities, business, financial condition and results of operations. Even if the Company prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Company's financial condition.

Insurance

Journey's involvement in the exploration, development and production of oil and natural gas properties may result in Journey becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Company maintains insurance 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. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, Journey may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance, or for other reasons. The payment of any uninsured liabilities would reduce the funds available to Journey. The occurrence of a significant event that Journey is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on Journey's business, financial condition, results of operations and prospects.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, Journey may disclose confidential information relating to its business, operations or affairs. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put Journey at competitive risk and may cause significant damage to its business. The harm to Journey'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, Journey 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.

Seasonality and Extreme Weather Conditions

The level of activity in the Canadian oil 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 may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Roads bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. Certain oil and natural gas producing 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 muskeg. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its oil, natural gas and NGLs production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Waterfloods

The Company currently undertakes or may undertake in the future certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities, the Company needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Company will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If the Company is unable to access such water, it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reservoirs. In addition, the Company may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Company's results of operations.

Regulation of Hydraulic Fracturing

Journey uses hydraulic fracturing in its operations. Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to fracture such formations and thereby stimulate oil and natural gas production. Hydraulic fracturing is used to produce commercial quantities of oil and natural gas from reservoirs. Negative perception of hydraulic fracturing may place pressure on governments in jurisdictions where Journey operates to implement additional regulatory requirements or limitations on utilization of hydraulic fracturing, which in turn could restrict Journey’s operations and increase its costs. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or government claims, and could increase the Company’s costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reservoirs.

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, and Rocky Mountain House. The AER announced in February 2015, seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events, and the suspension of operations if a seismic event above a particular threshold occurs. These requirements will remain in effect as long as the AER deems them necessary. In March 2018 and March 2019, two earthquakes felt in Red Deer and Sylvan Lake were characterized as seismic activity induced by hydraulic fracturing. In March 2019, the AER suspended operations of an oil and natural gas company in the area where the earthquake occurred, pending further investigation. In May 2019, the suspended oil and natural gas company was able to resume operations with a risk assessment plan in place that was approved by the AER. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Conflicts of Interest

Certain of Journey's directors or officers may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA, which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to a material contract or proposed material contract with the Company to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Directors and Officers – Conflicts of Interest*".

Expansion into New Activities

Journey's operations and the expertise of its management are currently focused primarily on oil and gas production, exploration and development in the Western Canadian Sedimentary Basin. 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. In 2020 Journey started generating electricity from its recently constructed 4.0 MW electricity generation facility. While revenues from this asset are still an immaterial portion of Journey's overall corporate operations, as this segment of the business increases, Government regulations related to this new activity could materially impact its operations and profitability.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Journey and may delay exploration and development activities.

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit GHG which may require the Corporation 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 Corporation's business, financial condition, results of operations and prospects. Some of the Corporation'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. See "*Risk Factors – Seasonality and Extreme Weather Conditions*". 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 Corporation 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 Corporation 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. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

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 Corporation's operating expenses, and, in the long-term could potentially reduce demand for oil and natural gas production, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or requiring asset impairments for financial statement purposes. See *"Industry Conditions – Climate Change Regulation", "Risk Factors – Non-Governmental Organizations and Eco-Terrorism Risks", "Risk Factors – Reputational Risk Associated with the Corporation's Operations" and "Risk Factors – Changing Investor Sentiment"*.

Information Technology Systems and Cyber Security

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, manage financial resources, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our 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 Corporation becomes a victim to a cyber-phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Corporation's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Corporation's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

The Corporation maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments. The Corporation also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Corporation's efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage its information technology infrastructure. The Corporation applies technical and process controls in line with industry-accepted standards to protect its information, assets and systems, including a written incident response plan for responding to a cyber-security incident. However, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation, and any damages sustained may not be adequately covered by the Corporation's current insurance coverage, or at all. 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 Corporation's business, financial condition and results of operations.

The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. 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 Corporation's business, financial condition and results of operations.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continue to affect the marketability and price of oil and natural gas acquired or discovered by Journey. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of Journey's net production revenue.

In addition, the Company's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of Journey's properties, wells or facilities are the subject of a terrorist attack, it may have a material adverse effect on the business, financial condition, results of operations and prospects. Journey does not have insurance to protect against the risk from terrorism.

Non-Governmental Organizations and Eco-Terrorism Risks

The oil and natural gas exploration, development and operating activities conducted by the Corporation may, at times, be subject to public opposition. Such public opposition could expose the Corporation to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that the Corporation will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Corporation to incur significant and unanticipated capital and operating expenditures. In addition, the Corporation's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Indigenous Claims

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

Internal Controls

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

Additional information on the risks, assumptions and uncertainties are found in this AIF under the heading "*Forward-looking Statements*".

STATEMENT OF RESERVES DATA

Statement of Reserves Data and Other Oil and Natural Gas Information

The statement of reserves data and other oil and natural gas information set forth below is dated March 9, 2021. The statement is effective as of December 31, 2020 and the preparation date of the statement is March 9, 2021. The Report On Reserves Data By Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Appendices “A” and “B” to this AIF, respectively.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by GLJ with an effective date of December 31, 2020 as contained in the GLJ Report. The reserves data summarizes the crude oil, natural gas and natural gas liquids reserves of Journey and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. Journey engaged GLJ to provide an evaluation of its proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Journey’s reserves are in the Province of Alberta.

Journey determined the future net revenue and present value of future net revenue after income taxes by utilizing GLJ’s before income tax future net revenue and estimate of income tax. The estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of Journey’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 Journey’s oil and gas properties reflects the tax burden of its properties on a stand-alone basis. It does not provide an estimate of the value of Journey as a business entity, which may be significantly different.

All evaluations of future net revenue are after the deduction of royalties; development costs; production costs; and the abandonment and reclamation costs associated with all active and inactive wells, future development locations that have reserves assigned to them, facilities, pipelines and gathering systems; and 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 GLJ represent the fair market value of those reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ 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 definitions and information contained in “*Presentation of Oil and Gas Reserves and Production Information - Glossary of Selected Oil and Gas Terms*” in conjunction with the following tables and notes. The recovery and reserve estimates described herein are estimates only. The actual reserves associated with Journey’s properties may be greater or less than those calculated. See “*Risk Factors*”.

The tables below summarize the data contained in the GLJ Report and, as a result, may contain slightly different numbers than such report due to rounding. In addition, certain columns may not add exactly due to rounding.

Summary of Reserves (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AS OF DECEMBER 31, 2020
FORECAST PRICES AND COSTS

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbls)	LIGHT AND MEDIUM OIL Net (Mbbls)	HEAVY OIL (1) Gross (Mbbls)	HEAVY OIL (1) Net (Mbbls)	TIGHT OIL Gross (Mbbls)	TIGHT OIL Net (Mbbls)
PROVED:						
Developed Producing	4,354	3,873	2,412	2,213	128	122
Developed Non-Producing	319	287	7	6	0	0
Undeveloped	2,365	1,875	1,775	1,581	119	109
TOTAL PROVED	7,038	6,035	4,194	3,801	247	231
PROBABLE	6,433	5,477	3,027	2,678	110	91
TOTAL PROVED PLUS PROBABLE	13,470	11,512	7,221	6,479	357	322

RESERVES CATEGORY	CONVENTIONAL NATURAL GAS Gross (MMcf)	CONVENTIONAL NATURAL GAS Net (MMcf)	SHALE GAS Gross (MMcf)	SHALE GAS Net (MMcf)	COAL BED METHANE Gross (MMcf)	COAL BED METHANE Net (MMcf)
PROVED:						
Developed Producing	52,020	46,331	340	334	14,212	13,011
Developed Non-Producing	7,089	5,900	0	0	658	603
Undeveloped	14,452	13,395	168	157	0	0
TOTAL PROVED	73,562	65,625	507	491	14,871	13,613
PROBABLE	47,991	43,582	278	257	9,929	9,087
TOTAL PROVED PLUS PROBABLE	121,553	109,207	786	747	24,800	22,701

RESERVES CATEGORY	NATURAL GAS LIQUIDS Gross (Mbbls)	NATURAL GAS LIQUIDS Net (Mbbls)	OIL EQUIVALENT Gross (Mboe)	OIL EQUIVALENT Net (Mboe)
PROVED:				
Developed Producing	2,112	1,738	20,102	17,893
Developed Non-Producing	278	208	1,895	1,585
Undeveloped	502	469	7,199	6,292
TOTAL PROVED	2,893	2,415	29,195	25,770
PROBABLE	1,540	1,360	20,809	18,427
TOTAL PROVED PLUS PROBABLE	4,433	3,775	50,004	44,197

(1) The crude oil in Journey's heavy oil reserves classification is approximately 20° API and is therefore classified as heavy oil under NI 51-101.

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED (%/year) AS OF DECEMBER 31, 2020 FORECAST PRICES AND COSTS

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% per Year $/boe[1]
PROVED:						
Developed Producing	(109,768)	50,772	77,212	78,559	74,558	4.32
Developed Non-Producing	17,336	12,652	9,900	8,111	6,861	6.24
Undeveloped	104,422	54,885	30,040	16,042	7,526	4.77
TOTAL PROVED	11,990	118,308	117,153	102,712	88,944	4.55
PROBABLE	329,673	195,099	127,965	89,679	65,824	6.94
TOTAL PROVED PLUS PROBABLE	341,663	313,407	245,118	192,391	154,769	5.55

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

NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED (%/year) AS OF DECEMBER 31, 2020 FORECAST PRICES AND COSTS

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	(109,768)	50,772	77,212	78,559	74,558
Developed Non-Producing	17,336	12,652	9,900	8,111	6,861
Undeveloped	104,422	54,885	30,040	16,042	7,526
TOTAL PROVED	11,990	118,308	117,153	102,712	88,944
PROBABLE	329,673	195,099	127,965	89,679	65,824
TOTAL PROVED PLUS PROBABLE	341,663	313,407	245,118	192,391	154,769

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2020 FORECAST PRICES AND COSTS[(1)(2)]

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS[(3)] ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	FUTURE INCOME TAX EXPENSES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Total Proved	1,066,102	118,695	530,081	90,152	315,184	11,990	-	11,990
Total Proved plus Probable	1,963,098	226,298	880,048	187,952	327,136	341,663	-	341,663

Notes:

(1) Total revenue includes Company revenue before royalty and includes other income.
(2) Royalties include Crown, freehold and overriding royalties and mineral tax.
(3) Reflects estimated abandonment and reclamation costs associated with all active and inactive wells, future development locations that have reserves assigned to them, facilities, pipelines and gathering systems.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2020
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES(2) (discounted at 10%/year) ($000s)	UNIT VALUE BEFORE INCOME TAX(2) (discounted at 10%/year) ($/boe)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	62,055	6.54
	Heavy Oil (including solution gas and other by-products) (1)	26,869	6.87
	Shale Gas (including by-products but excluding solution gas)	2,031	5.86
	Conventional Natural Gas (including by-products but excluding solution gas)	21,905	2.24
	Coal Bed Methane	4,293	1.89
	Total	117,153	4.55
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	134,074	7.33
	Heavy Oil (including solution gas and other by-products) (1)	60,210	9.10
	Shale Gas (including by-products but excluding solution gas)	4,145	8.34
	Conventional Natural Gas (including by-products but excluding solution gas)	38,811	2.59
	Coal Bed Methane	7,878	2.08
	Total	245,118	5.55

Note:
(1) The crude oil in Journey's heavy oil reserves classification is approximately 20° API and is therefore classified as heavy oil under NI 51-101.
(2) Other Company revenue and costs not allocated to a specific production group have been allocated proportionally to production groups. Unit values are based on the Company net reserves.

Pricing Assumptions

The forecast cost and price assumptions above assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. The following crude oil and natural gas benchmark reference pricing, inflation and exchange rates were utilized in the GLJ Report and are the average of the published forecasts for GLJ, Sproule Associates Ltd. and McDaniel & Associates Consultants Ltd.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF JANUARY 1, 2021
FORECAST PRICES AND COSTS

	OIL				NATURAL GAS		NATURAL GAS LIQUIDS				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Oil Price 40° API ($Cdn/bbl)	WCS Crude Oil Stream Hardisty ($Cdn/bbl)	Hardisty Bow River Stream Quality ($Cdn/bbl)	AECO Gas Price ($Cdn/MMBtu)	NYMEX Henry Hub ($US/MMBtu)	Edmonton Propane ($Cdn/bbl)	Edmonton Butane ($Cdn/bbl)	Edmonton Pentanes Plus ($Cdn/bbl)	INFLATION RATE (1) %/Year	EXCHANGE RATE (2) ($US/$Cdn)
2021	47.17	55.76	44.63	45.36	2.78	2.83	18.18	26.36	59.24	0.0	0.7683
2022	50.17	59.89	48.18	48.96	2.70	2.87	21.91	32.85	63.19	1.3	0.7650
2023	53.17	63.48	52.10	52.92	2.61	2.90	24.57	39.20	67.34	2.0	0.7633
2024	54.97	65.76	54.10	54.95	2.65	2.96	25.47	40.65	69.77	2.0	0.7633
2025	56.07	67.13	55.19	56.05	2.70	3.02	26.00	41.50	71.18	2.0	0.7633
2026	57.19	68.53	56.29	57.16	2.76	3.08	26.54	42.36	72.61	2.0	0.7633
2027	58.34	69.95	57.42	58.30	2.81	3.14	27.09	43.24	74.07	2.0	0.7633
2028	59.50	71.40	58.57	59.47	2.86	3.20	27.65	44.14	75.56	2.0	0.7633
2029	60.69	72.88	59.74	60.66	2.92	3.26	28.23	45.06	77.08	2.0	0.7633
2030	61.91	74.34	60.93	61.87	2.98	3.33	28.79	45.96	78.62	2.0	0.7633
2031	63.15	75.83	62.15	63.11	3.04	3.39	29.37	46.88	80.19	2.0	0.7633
2032	64.41	77.34	63.39	64.37	3.10	3.46	29.96	47.82	81.80	2.0	0.7633
2033	65.70	78.89	64.66	65.66	3.16	3.53	30.55	48.78	83.43	2.0	0.7633
2034	67.01	80.47	65.95	66.97	3.23	3.60	31.16	49.75	85.10	2.0	0.7633
2035	68.35	82.08	67.28	68.31	3.29	3.67	31.79	50.75	86.80	2.0	0.7633
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.7633

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by Journey for the year ended December 31, 2020 were $39.06/bbl for light and medium crude oil; $34.27/bbl for heavy crude oil; $18.75/bbl for natural gas liquids; and $1.94/Mcf for natural gas (conventional and CBM combined).

Reserves Reconciliation

The following table sets forth the reconciliation of our gross reserves as at December 31, 2020, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2020 and as at December 31, 2019 include working interest reserves before royalties payable and without including gross royalties receivable. Key highlights include:

- Total Proved technical revisions were 1,693 Mboe due to improved performance at various properties. Approximately 51% of the total revisions were from natural gas with 37% from conventional natural gas, 13% from coalbed methane and 1% from shale gas. Approximately 49% of the total revisions came from oil and natural gas liquids with 28% from heavy oil, 17% from conventional light and medium oil and 4% from natural gas liquids.
- Total Proved plus Probable technical revisions were (648) Mboe. Positive revisions in total natural gas and heavy oil were not enough to offset negative revisions in tight oil from the removal of certain Duvernay wells that were unlikely to be drilled prior to land expiries.
- Journey observed a negative impact in the Economic Factors category mainly as a result of lower oil and gas price forecasts year over year. Proved reserves were reduced by 2,932 Mboe with all oil and natural gas liquids representing approximately 67% of the total and all natural gas representing 33% of the

total. Proved plus Probable reserves were reduced by 3,924 Mboe with all oil and natural gas liquids representing approximately 55% of the total and all natural gas representing 45% of the total.

- Total Natural Gas Liquids shown below includes associated natural gas liquids from both Conventional and Shale/Tight reservoirs.

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE / FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			TIGHT OIL		
	Proved (Mbbls)	**Probable (Mbbls)**	**Proved Plus Probable (Mbbls)**	**Proved (Mbbls)**	**Probable (Mbbls)**	**Proved Plus Probable (Mbbls)**	**Proved (Mbbls)**	**Probable (Mbbls)**	**Proved Plus Probable (Mbbls)**
December 31, 2019	8,334	6,759	15,093	4,081	2,925	7,006	1,106	1,514	2,620
Discoveries	0	0	0	0	0	0	0	0	0
Extensions and Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions	285	(388)	(103)	474	84	559	(4)	(1,620)	(1,624)
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
Economic Factors	(693)	62	(631)	(97)	17	(80)	(855)	217	(638)
Production	(888)	0	(888)	(264)	0	(264)	0	0	0
December 31, 2020	7,038	6,433	13,470	4,194	3,027	7,221	247	110	357

	CONVENTIONAL NATURAL GAS			SHALE GAS			COALBED METHANE		
	Proved (MMcf)	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**
December 31, 2019	81,770	53,191	134,961	1,411	2,067	3,478	16,018	9,854	25,872
Discoveries	0	0	0	0	0	0	0	0	0
Extensions and Improved Recovery	337	89	426	0	0	0	0	0	0
Technical Revisions	3,764	(571)	3,193	98	(1,974)	(1,876)	1,366	281	1,647
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
Economic Factors	(4,414)	(4,718)	(9,132)	(1,002)	185	(817)	(440)	(206)	(646)
Production	(7,895)	0	(7,895)	0	0	0	(2,074)	0	(2,074)
December 31, 2020	73,562	47,991	121,553	507	278	786	14,871	9,929	24,800

	TOTAL NATURAL GAS LIQUIDS			OIL EQUIVALENT		
	Proved (Mbbls)	**Probable (Mbbls)**	**Proved Plus Probable (Mbbls)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved Plus Probable (Mboe)**
December 31, 2019	3,368	2,073	5,442	33,422	24,124	57,546
Discoveries	0	0	0	0	0	0
Extensions and Improved Recovery	12	4	16	68	18	87
Technical Revisions	67	(40)	27	1,693	(2,341)	(648)
Acquisitions	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0
Economic Factors	(312)	(498)	(809)	(2,932)	(992)	(3,924)
Production	(242)	0	(242)	(3,056)	0	(3,056)
December 31, 2020	2,893	1,540	4,433	29,195	20,809	50,004

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 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 GLJ Report contains proved and probable undeveloped reserves that have been estimated in accordance with the procedures and standards contained in the COGE Handbook.

Journey plans to develop substantially all of the proved and probable undeveloped reserves in the GLJ Report over the next five years. Journey allocates development capital annually as part of an annual budgeting process. Risk can be reduced by technically reviewing prior year's results before committing additional capital. Optimal pace of development and allocation of capital will lead to development time frame exceeding two years for Journey's undeveloped reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

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

	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2018	418	3,000	-	1,300	2,455	22,409	6	893
2019	170	2,544	-	1,299	122	15,494	63	673
2020	-	2,365	300	1,775	-	14,452	-	502

	Tight Oil (Mbbls)		Shale Gas (MMcf)		Oil Equivalent (Mboe)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2018	-	-	-	-	833	8,928
2019	956	956	1,123	1,123	1,396	8,242
2020	-	119	-	168	300	7,199

GLJ has assigned 7,199 Mboe of proved undeveloped reserves in the GLJ Report under forecast prices and costs, which includes $79.7 million of associated undiscounted future development capital. Forecast spending for the next two years is $33.6 million.

Probable Undeveloped Reserves

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

	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2018	157	4,787	275	1,894	924	28,933	2	960
2019	225	4,741	-	1,887	293	31,122	107	1,424
2020	-	4,682	150	1,972	-	26,594	-	911

	Tight Oil (Mbbls)		Shale Gas (MMcf)		Oil Equivalent (Mboe)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2018	-	-	-	-	588	12,463
2019	1,435	1,435	1,905	1,905	2,134	14,993
2020	-	30	-	60	150	12,038

GLJ has assigned 12,038 Mboe of probable undeveloped reserves in the GLJ Report under forecast prices and costs which includes $95.2 million of associated undiscounted future development capital. Forecast spending for the next two years is $8.6 million.

Significant Factors or Uncertainties Affecting Reserves Data

Changes in forecast commodity prices relative to the forecasts provided under "*Pricing Assumptions*" above could have a negative impact on the Company's reserves and, in particular, the development of our undeveloped reserves unless future development costs are adjusted at the same time. Other than the foregoing and the factors disclosed or described in the tables above, Journey does not anticipate that any significant economic factors or significant uncertainties will affect any particular components of its reserves data. However, Journey's reserves can be significantly affected by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes, abandonment and reclamation costs and well performance that are beyond the Company's control. See "*Risk Factors*".

Abandonment and Reclamation Costs

The costs to abandon and reclaim all of Journey's producing and non-producing wells, gas plants, pipelines, batteries, and other facilities have been estimated by Journey in consultation with industry consultants who are knowledgeable in these matters. No estimate of salvage value is netted against these estimated costs. The Company's model for estimating the amount of future abandonment and reclamation expenditures is done at the well and facility levels. Estimated costs for each well, pipeline segment and facility are based on an external consultant's estimates and then adjusted by internal technical personnel to take into account specific additional information that is unique to those properties. Each well, pipeline and facility is assigned a cost for abandonment and reclamation that is unique to the type of property, taking into account its geographic location, well depth, and producing zones, among other factors. The timing of the expenditures is based on the end of the productive life for the specific wells as estimated by a third party consultant, and also taking into account governmental requirements. Facility reclamation costs are generally scheduled to begin shortly after the end of the reserve life for the specific field for the associated reserves.

As at December 31, 2020 there were 1,938 gross (1,512.0 net) wells for which Journey expects to incur abandonment and reclamation costs; and 276 gross (171.1 net) wells for which abandonment work is complete but the site require reclamation work only.

The GLJ Report deducted $327.1 million (undiscounted) for abandonment and reclamation costs associated with all active and inactive wells, future development locations that have reserves assigned to them, facilities, pipelines and gathering systems, in estimating the future net revenues disclosed above. A comprehensive estimate of future abandonment and reclamation costs for all of Journey's existing wells, facilities, surface leases, and pipelines is provided for in the financial statements of Journey. These amounts are described in Note 10 of the December 31, 2020 audited, annual financial statements.

Future Development Costs

The following table sets forth development costs deducted in the estimation of Journey's future net revenue attributable to the reserve categories noted below.

	FUTURE DEVELOPMENT COSTS	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2021	7,478	7,478
2022	29,672	38,925
2023	25,064	59,453
2024	21,889	46,046
2025	1,550	29,460
Thereafter	4,499	6,590
Total (Undiscounted)	90,152	187,952
Total (Discounted at 10%)	71,396	142,561

Journey expects to fund the development costs of its reserves through a combination of internally generated funds flow, debt and equity issuances. 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 GLJ Report. Failure to develop those reserves could have a negative impact on Journey's future funds flow.

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

Other Oil and Natural Gas Information

Principal Oil and Natural Gas Properties

The following is a description of Journey's principal oil and natural gas properties on production or under development as at December 31, 2020. Information in respect of production volumes is average annual sales volumes, net to Journey.

Countess, Alberta

The Greater Countess area is located adjacent to Brooks, Alberta and includes production from the Countess and Brooks properties. Countess production is comprised of shallow gas from the Milk River/Medicine Hat formations, coal bed methane from Belly River coal formations and production of oil and associated gas predominantly from the Glauconitic and Sunburst formations. The Milk River and Medicine Hat sequence is dominated by marine sandstones. Substantially all of Journey's shallow gas wells have been additionally completed uphole in the coal units of the Belly River formation. Countess and Brooks oil is characterized by its large oil in place, low recovery medium gravity oil (25˚ to 30˚ API) in the Glauconitic and Sunburst formations. The Glauconitic formation is dominated by shore face sandstone deposits and channel sandstones. These fine grained sandstone reservoirs were originally developed with vertical wells, and have since been further exploited with horizontal multi-frac drilling. In addition, the underlying Sunburst formation is an estuarine valley fill sandstone deposit. These fine grained sandstone reservoirs were also originally developed with vertical wells, and have since been further exploited with horizontal drilling using conventional completions. A significant inventory of development drilling in both zones and subsequent water flood comprises the bulk of the upside of this asset. Average 2020 production at the Greater Countess area was 1,758 boe/d, which was comprised of 30% conventional natural gas, 56% coal-bed methane natural gas, and 14% light/medium crude oil.

Matziwin, Alberta

The Matziwin property is located approximately 50 kilometers north of Brooks, Alberta. Matziwin is characterized by its large oil in place, low recovery medium gravity oil (30˚ API) and associated natural gas production. In the area, production is primarily from the Glauconitic formation, dominated by shoreface sandstone deposits. These fine grained sandstone reservoirs were originally developed with vertical wells, and have since been further exploited with horizontal multi-frac drilling. A significant inventory of development drilling locations and subsequent water flood comprises the bulk of the upside of this asset. Average 2020 production at Matziwin was 1,747 boe/d comprised of 55% conventional natural gas and 45% of light/medium crude oil.

Gilby, Alberta

The Greater Gilby area is located just northwest of Red Deer, Alberta and includes assets in the vicinity of Gilby and Gull Lake Alberta. Production from the area is mainly gas and associated liquids from the Glauconite formation and oil from the Mannville formation. Duvernay shale oil is the emerging project for this area, and Journey is a non-operated partner in a large joint venture in the area west of the town of Rimbey.

Glauconite gas and associated liquids produces from the Hoadley barrier island sandstone trend. This extensive gas field has been developed in phases over the past 30 years, initially with vertical wells, and more recently with horizontal wells. The formation varies in reservoir quality, but is generally low permeability, gas charged and slightly over-pressured. Journey's lands are partially developed with both vertical and horizontal wells, but a significant inventory of low risk horizontal wells remain to be drilled. Oil production at Gilby is predominantly from the Gilby Mannville B Unit which is a medium gravity (26˚ API) water flood where Journey holds 100% working interest.

Duvernay shale oil is an emerging play in the region, and Journey has amassed a large land base to target the play. The Duvernay is a silty shale, oil prone, highly over pressured and undeveloped on most of Journey's land base.

Through 2019, Journey has through its joint venture delineated and proven the play, with 3 producing and 1 well capable of production to date. Journey has a royalty interest in these wells prior to certain payout provisions before reversion to 29.17% working interest.

Average 2020 production at the Greater Gilby area was 1,289 boe/d and comprised of 67% conventional natural gas, 12% light/medium crude oil and 21% natural gas liquids.

Crystal, Alberta

The Greater Crystal area is located approximately 90 kilometres southwest of Edmonton, Alberta and production is mainly from properties at Crystal, Poplar Creek, Westerose and Berrymoor. At the Crystal property, oil production is from the Viking formation (40˚ API), which produces from an estuarine valley fill sandstone reservoir. Further upside exists in the exploitation of the Viking sandstone by drilling horizontally into the existing pool, drilling horizontal, multi-frac wells in the lower permeability portions of the pool, and expanding the existing water flood beyond the heart of the pool. At Poplar Creek and Westerose, Belly River oil (34˚ to 37˚ API) production occurs in several pools, producing from delta front shore face sandstone reservoirs, many of which are currently water flooded. Upside exists with infill horizontal multi-frac drilling, pool expansion and water flood expansion in several Belly River pools. The Westerose Banff B Unit is a stable, long life oil pool (29˚ API) currently under a gas reinjection scheme. Production occurs from the vuggy dolomite reservoir of the Banff Clarks member. Further drilling is contemplated for this pool to optimize recovery. At Berrymoor, low decline production is mainly from an Ostracod oil pool (31˚ API) which is currently under water flood.

Average 2020 production from the Greater Crystal area was 1,239 boe/d and comprised of 38% conventional natural gas, 45% light/medium crude oil and 17% natural gas liquids.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which Journey had a working interest as at December 31, 2020 and does not include 200 gross (145.4 net) service wells (injection, disposal, source water or observation wells), and 276 (171.1 net) abandoned wells (cut and capped but not reclaimed yet).

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	363	274.3	446	326.3	634	557.1	295	208.9
Total	363	274.3	446	326.3	634	557.1	295	208.9

Properties with No Attributed Reserves

The following table sets out the developed and undeveloped land holdings of Journey as at December 31, 2019.

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	338,267	245,559	194,297	121,141	532,565	366,700
Total	338,267	245,559	194,297	121,141	532,565	366,700

Of the properties set out above, 41,017 gross (26,857 net) acres are scheduled for expiry in 2021. Journey closely monitors land expiries and plans its development program with the strategy of minimizing expiries of undeveloped lands. Development of the Corporation's properties with no attributed reserves are subject to current industry conditions and uncertainties as indicated under "*Industry Conditions"* and *"Risk Factors"* herein.

Forward Contracts

Journey 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.

As at December 31, 2020 Journey has no risk management contracts outstanding.

Tax Horizon

Based on un-deducted the tax pools of Journey as at December 31, 2020, the anticipated capital spending profile, and forecasted commodity prices in the GLJ Report, it is not currently anticipated that Journey will pay cash taxes for at least the next five years.

Costs Incurred

The following table summarizes the capital costs incurred by Journey for the year ended December 31, 2020.

	Year ended December 31, 2020 ($000s)
Power generation asset construction	5,802
Exploration costs	4
Development costs	964
Mineral rights acquisition/retention	333
Property dispositions	(37)
Total	7,066

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Journey participated during the year ended December 31, 2020.

	Development		**Exploratory**	
	Gross	**Net**	**Gross**	**Net**
Natural Gas	-	-	-	-
Oil	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	-	-	-	-

For 2021, Journey will be concentrating its capital spending on maintenance and facility capital to support production from its existing wells.

Production Estimates

The following table sets out for each product type the gross volume of production estimated for 2021 in the estimates of gross proved reserves and gross probable reserves disclosed in the tables above. The Greater Countess and Matziwin areas each account for approximately 20% of the total gross proved plus probable reserves production for 2021.

	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)[(1)]	Tight Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Shale Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids (bbl/d)	Oil Equivalent (boe/d)
Proved								
Greater Countess	258	0	0	3,029	0	5,509	6	1,687
Matziwin	687	0	0	5,467	0	0	22	1,620
Other Alberta	1,423	752	22	12,757	58	0	601	4,934
Total Proved	2,368	752	22	21,253	58	5,509	629	8,241

	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)[(1)]	Tight Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Shale Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids (bbl/d)	Oil Equivalent (boe/d)
Probable								
Greater Countess	7	0	0	50	0	68	0	27
Matziwin	52	0	0	388	0	0	2	118
Other Alberta	20	35	2	249	6	0	12	113
Total Probable	79	35	2	687	6	68	14	258
Total Proved plus Probable	2,448	787	24	21,940	65	5,577	643	8,499

Note:
(1) The crude oil in Journey's heavy oil reserves classification is approximately 20° API and is therefore classified as heavy oil under NI 51-101.

Production History

The following tables summarize certain information in respect of the production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below.

	Quarter Ended 2020				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2020
Average Daily Production [(1)]					
Light and Medium Oil (bbl/d)	3,071	2,041	2,393	2,285	2,447
Heavy Oil (bbl/d)	737	586	796	767	722
Conventional Natural Gas (MMcf/d)	22,625	21,126	21,037	20,708	21,371
Coal-bed methane natural gas (MMcf/d)	6,197	6,055	5,889	5,458	5,899
Natural Gas Liquids (bbl/d)	713	651	635	661	665
Combined (boe/d)	9,325	7,808	8,311	8,074	8,379
Average Net Production Prices Received					
Light and Medium Oil (bbl/d)	41.32	25.32	43.47	43.59	39.06
Heavy Oil (bbl/d)	34.67	20.85	39.02	39.09	34.27
Conventional Natural Gas (MMcf/d)	1.10	1.85	2.10	2.59	1.90
Coal-bed methane natural gas (MMcf/d)	1.71	2.16	2.00	2.47	2.07
Natural Gas Liquids (bbl/d)	19.00	10.07	20.22	25.51	18.75
Combined (boe/d)	21.61	15.71	24.53	26.46	22.15

Royalties Paid					
Light and Medium Oil (bbl/d)	6.46	1.68	4.72	5.06	4.71
Heavy Oil (bbl/d)	3.24	1.89	2.84	2.85	2.75
Conventional Natural Gas (MMcf/d)	0.06	0.02	0.03	0.15	0.06
Coal-bed methane natural gas (MMcf/d)	0.20	0.14	0.23	0.29	0.21
Natural Gas Liquids (bbl/d)	6.56	2.50	2.06	4.97	4.10
Combined (boe/d)	3.18	0.95	2.02	2.69	2.25
Production Costs (2)(3)					
Light and Medium Oil (bbl/d)	24.80	25.04	23.81	23.75	24.36
Heavy Oil (bbl/d)	14.35	12.28	16.36	15.44	14.78
Conventional Natural Gas (MMcf/d)	1.51	1.08	1.21	1.17	1.25
Coal-bed methane natural gas (MMcf/d)	0.81	0.83	0.87	0.83	0.83
Natural Gas Liquids (bbl/d)	4.78	3.52	4.02	3.67	4.01
Combined (boe/d)	13.86	11.34	12.41	12.06	12.48
Transportation Costs					
Light and Medium Oil (bbl/d)	1.22	0.94	0.75	1.43	1.09
Heavy Oil (bbl/d)	1.51	2.04	1.62	2.07	1.80
Conventional Natural Gas (MMcf/d)	-	-	-	-	-
Coal-bed methane natural gas (MMcf/d)	-	-	-	-	-
Natural Gas Liquids (bbl/d)	0.15	0.06	0.09	0.12	0.11
Combined (boe/d)	0.53	0.40	0.38	0.61	0.48
Netback Received (4)					
Light and Medium Oil (bbl/d)	8.84	(2.34)	14.19	11.58	8.90
Heavy Oil (bbl/d)	15.57	4.64	18.20	18.73	14.94
Conventional Natural Gas (MMcf/d)	(0.47)	0.75	0.86	1.46	0.59
Coal-bed methane natural gas (MMcf/d)	0.70	1.19	0.90	1.35	1.03
Natural Gas Liquids (bbl/d)	7.51	3.99	14.05	16.75	10.53
Combined (boe/d)	4.04	3.02	9.72	11.10	6.94

Notes:

(1) Before the deduction of royalties.

(2) Production costs are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between product types. In addition, these include facility operating costs, net of third party recoveries including processing, treating and water disposal.

(3) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.

(4) See "*GAAP and Non-GAAP Measures*".

The following table indicates the average daily production from the important fields for the year ended December 31, 2020.

	Light/ Medium Crude Oil (bbl/d)	Heavy Crude Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	CBM Natural Gas (bbl/d)	NGLs (bbl/d)	Boe (boe/d)
Countess	243	-	3,154	5,899	6	1,758
Matziwin	767	-	5,737	-	24	1,747
Crystal	559	-	2,793	-	215	1,239
Gilby	150	-	5,201	-	272	1,289
Other	728	722	4,488	-	148	2,346
Total	2,447	722	21,373	5,899	665	8,379

DIVIDENDS AND DIVIDEND POLICY

Journey does not anticipate paying dividends in the immediate future and will instead direct cash flow to capital expenditures and debt reduction.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of the Company as of the date hereof consists of an unlimited number of Common Shares, an unlimited number of Restricted Voting Shares and an unlimited number of Preferred Shares. As of the date of this AIF, there were 44,001,158 Common Shares issued and outstanding and no Restricted Voting Shares or Preferred Shares issued and outstanding. The following is a description of the rights, privileges, restrictions and conditions attaching to Journey's share capital.

Common Shares

The Common Shares have the following rights, privileges, restrictions and conditions:

> *Voting Rights*: Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of the Shareholders (except meetings at which only holders of a specified class of shares are entitled to vote).
>
> *Dividends*: Holders of Common Shares are entitled to receive dividends as and when declared by the Board of Directors on the Common Shares as a class, subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Company and provided that no dividend shall be declared on the Common Shares unless a dividend in the same per share amount is declared on the Restricted Voting Shares.
>
> *Ranking*: In the event of any liquidation, dissolution or winding-up of Journey, whether voluntary or involuntary, or any other distribution of Journey assets among its Shareholders for the purpose of winding-up Journey's affairs, and subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Company, holders of Common Shares are entitled to receive the remaining property of the Company upon dissolution in the same per share amount with the holders of Restricted Voting Shares.

The Common Shares also contain tag along rights to the benefit of the Restricted Voting Shares, which provide that in the event that an Exclusionary Offer (as defined below) is made, then an offer to acquire the Restricted Voting Shares must be made that is identical to the Exclusionary Offer in terms of price per share, percentage of outstanding shares to be taken up and in all other material respects. An "Exclusionary Offer" is defined as an offer to purchase Common Shares which must be made, by reason of applicable law or by the regulations or policies of any stock exchange on which the Common Shares are listed, to all or substantially all of the holders of Common Shares.

As at the date hereof, shareholders owning more than 10% of the Common Shares of Journey are: AIMCo with 7,740,700 Common shares (representing 17.59% of the outstanding Common Shares); and PSP with 5,432,308 Common Shares (representing 12.35% of the outstanding Common Shares).

Restricted Voting Shares

On June 6, 2014, the Company amended its articles to create the Restricted Voting Shares. The Restricted Voting Shares have the same rights, privileges, restrictions and conditions as the Common Shares set out above (and will rank equally with the Common Shares in respect to the right to receive dividends as and when declared by the Board of Directors and the right to receive Journey assets in the event of any liquidation, dissolution or winding-up of Journey), except holders of Restricted Voting Shares shall not be entitled to vote in respect of the election of directors of the

Company and the Restricted Voting Shares shall automatically be converted into Common Shares on a 1:1 basis upon the sale of such Restricted Voting Shares to any third party and for no consideration payable in connection thereof.

A holder of Restricted Voting Shares shall have the right at any time or from time to time, upon providing notice to the Company, to convert all or any number of the outstanding Restricted Voting Shares held by such holder into Common Shares on the basis of one Common Share for each Restricted Voting Share, without payment of any additional consideration by such holder.

There are currently no Restricted Voting Shares outstanding.

Preferred Shares

The Preferred Shares are issuable in series having such rights, restrictions, privileges, conditions and designations as the Board may from time to time determine.

The Preferred Shares shall be entitled to preference over the Common Shares (and any other shares of the Company ranking junior to the Preferred Shares) with respect to payment of dividends and distribution of assets in the event of liquidation, dissolution or winding up of the Company, whether voluntary or involuntary, to the extent fixed in the case of each respective series, and may also be given such other preferences over the Common Shares (and any other shares of the Company ranking junior to the Preferred Shares) as may be fixed in the case of each such series.

There are currently no Preferred Shares outstanding.

Syndicated Bank Credit Agreement

During the first phase of the COVID-19 pandemic, the oil and gas industry experienced the largest single oil price decline in history. For Journey, 2020 started with strong commodity prices but by March, the world fell victim to the turmoil of the pandemic. The sharp decline in commodity prices put extraordinary stress on the reserve values that supported Journey's syndicated bank borrowings. Accordingly, the banks reduced the borrowing base and as a result Journey became drawn in excess of this new, lower, borrowing base level. Cash flows associated with these low commodity prices were insufficient for Journey to repay this deficiency. In addition, the asset disposition market had collapsed and a disposition at a sufficient price to repay the banks was not possible. The Company spent from April to October of 2020 in forbearance with the banks, while trying to work out a solution.

These efforts culminated in a multi-party transaction on October 30, 2020, whereby Journey's largest shareholder and debt provider, AIMCo, loaned Journey $38 million to buy out the outstanding bank debt of $75 million. In addition to the initial $38,000 payment to the syndicate, Journey will be contingently liable to pay a maximum of $5.75 million over a three year period with annual payments dependent on the achievement of specified price ranges for mixed, sweet, blended oil prices at the Edmonton, Alberta hub as reported by Natural Resources Canada. The payment in 2021 is capped at $0.75 million; 2022 is capped at $2.25 million; and in 2023 the payment is capped at the maximum total obligation of $5.75 million.

Senior Secured Credit Agreement

On October 6, 2016, Journey entered into a private placement with AIMCo for the issuance of 30,000 units at a price of $1,000 per unit for aggregate proceeds of $30 million. Each unit is comprised of: i) one promissory note with a par value of $1,000 which bears interest at the rate of 7.65% per annum payable semi-annually; and ii) 165 Common Share purchase warrants. The Promissory Notes (2016) mature on October 31, 2020 and all or a portion of the principal amount outstanding thereunder may be repaid by Journey without penalty after two years from the date of issuance. Journey issued 4.95 million warrants in connection with this promissory note private placement, with each warrant entitling the holder to purchase one Common Share at a price per share of $2.75 until their expiry on October 7, 2019.

On March 2, 2017, AIMCo exercised all of their warrants and gross proceeds of $13.6 million were received by Journey.

On January 31, 2018, Journey entered into a second promissory note private placement with AIMCo for the issuance of 22,000 units at a price of $1,000 per unit for aggregate proceeds of $22 million. Each unit is comprised of: i) one promissory note with a par value of $1,000 which bears interest at the rate of 7.65% per annum payable semi-annually; and ii) 105 Common Share purchase warrants. The Promissory Notes (2018) mature on September 30, 2022 and all or a portion of the principal amount outstanding thereunder may be repaid by Journey without penalty after two years from the date of issuance. Journey issued 2.31 million warrants in connection with this promissory note private placement, with each warrant entitling the holder to purchase one Common Share at a price per share of $2.51 until their expiry on June 1, 2020.

On September 30, 2019 all outstanding promissory notes were restructured into a single, second lien, term debt comprised of two tranches. The Promissory Notes (2016) had an aggregate principal amount of $30 million and a maturity date of October 31, 2020. These notes were restructured into a second lien tranche with a principal amount of $22 million with $8 million being repaid by Journey at closing. The maturity of this tranche was extended from October 31, 2020 to October 31, 2023 and the interest rate was changed to 11.5% per annum from 7.65% per annum. 1,331,617 share purchase warrants were issued at an exercise price of $3.15 per warrant in consideration for the change in terms. The Promissory Notes (2018) had a principal amount of $22 million and an interest rate of 7.65% per annum with a maturity of September 30, 2023. No changes were made to the financial terms of this tranche. The warrants previously issued with the 2018 promissory notes were voluntarily surrendered by AIMCo for cancellation.

On October 30, 2020, Journey secured a $38 million of term debt from AIMCo to fund the settlement of the $75 million credit facility with its syndicate of first-lien lenders. The $38 million of term debt was provided in three tranches. The first is for $15 million; bears interest at 11.5% per annum; and matures on June 30, 2021. The maturity of this first tranche was originally December 31, 2020 to coincide with the disposition of Journey's Countess, Alberta assets. The agreement for the sale of assets was terminated on March 1, 2021 and AIMCo extended the maturity to June 30, 2021. Journey repaid $3.75 million of this tranche on March 2, 2021. The second tranche is for $10 million; matures on October 31, 2021 and bears interest at 9.0% per annum. The third tranche of new debt is for a principal amount of $13 million; matures on October 31, 2024; and bears interest of 9.0% in year one, 9.85% in year two and 12.95% for years three and four.

In connection with the term debt advances Journey issued five million share-purchase warrants to AIMCo. The warrants entitle the holder to purchase one common share of Journey at an exercise price of $0.16 per warrant prior to their expiry date of October 30, 2024. In addition, a commitment fee loan, of $5,350 is payable to AIMCo on October 30, 2024 and bears interest at rates which are dependent upon Edmonton mixed sweet reference oil prices. Below $65 per barrel the loan bears no interest. Between $65 and $80 per barrel, the loan bears interest at 5.0% per annum and if oil prices exceed $80 per barrel the loan bears interest at 10.0% per annum.

The Senior Secured First Lien Debt is secured by a floating charge debenture over all of the Company's assets. There is a financial covenant that requires the Company to maintain its Liability Management Rating greater than 1.75. In addition, there are certain standard non-financial covenants in the term debt agreement. Journey was in compliance with all covenants as at December 31, 2020 and remains in compliance as of this date.

MARKET FOR SECURITIES

Trading Price and Volume

The outstanding Common Shares of the Company trade on the TSX under the symbol JOY and on the United States over the counter market (OTCQX) under the symbol JRNGF. The following table sets out the high and low closing prices and average trading volume of Common Shares as reported by the TSX, for the periods indicated.

Period	TSX High Close	TSX Low Close	TSX Average Daily Trading Volume
2020			
January	$1.70	$1.08	7,323
February	$1.16	$0.70	11,121
March	$1.16	$0.06	14,521
April	$0.58	$0.25	58,344
May	$0.70	$0.43	18,690
June	$0.55	$0.35	64,375
July	$0.42	$0.29	10,322
August	$0.38	$0.21	33,529
September	$0.24	$0.13	24,051
October	$0.18	$0.10	23,711
November	$0.33	$0.15	51,401
December	$0.33	$0.23	37,113
2021			
January	$0.36	$0.22	39,214
February	$0.40	$0.29	52,100
March 1 – 22	$1.40	$0.34	302,361

Prior Sales

Set forth below are details of the securities issued by the Company for the periods indicated.

Date of Issuance	Number and Type of Securities	Price per Security ($)	Aggregate Funds Received (Paid) ($)
November 30, 2020	914,440 Common Shares issued on the vesting of restricted stock unit and performance share units	0.15	Nil

During the year ended December 31, 2020, the securities that the Company issued, which were outstanding but not listed or quoted on a marketplace were 5,000,000 warrants issued as part of the issuance of new term debt on October 30, 2020.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

As at the date hereof, none of the Company's securities are subject to contractual restrictions on transfer.

DIRECTORS AND OFFICERS

Summary Information

The name, city of residence, and principal occupation during the last five years of each of the current directors and officers of the Company are set forth in the following table.

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since
Alex G. Verge Alberta, Canada	President and Chief Executive Officer and Director	Director and President and Chief Executive Officer of Journey since July 1, 2012.	July 1, 2012[(2)]
Howard Crone[(1)(3)(4)(5)] Alberta, Canada	Chairman	Independent businessman. Director of Cequence Energy Ltd. from July 2009 until September 28, 2020. From April 9 to July 27th of 2019 Mr. Crone served as interim CFO of Cequence. Prior thereto he was the Executive Vice President and Chief Operating Officer of Cequence from September 2010 to August 14, 2014.	May 2, 2014
Dana B. Laustsen[(1)(5)] Alberta, Canada	Director	Independent businessman. Prior thereto, Executive Vice President and Chief Operating Officer of GLJ	January 16, 2014
Craig H. Hansen[(1)(4)(5)]	Director	President of Zargon Oil and Gas Ltd. and its predecessor, Zargon Energy Trust since 1993.	August 6, 2019
Ryan Shay[(3)(4)(5)] Alberta, Canada	Director	Independent businessman and also a director of Crew Energy Inc. and Perpetual Energy Inc. Prior thereto, Mr. Shay was Managing Director, Head of Investment Banking at Cormark Securities until he retired in June of 2019. Mr. Shay was with Cormark since 1999.	May 24, 2019
Gerald N. Gilewicz Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Journey since September 4, 2012.	N/A
Brett Boklaschuk Alberta, Canada	Vice President, Geosciences	Vice President, Geosciences of Journey since May 12, 2015; previously served as the Manager of Business Development at Journey from November 2012.	N/A
Terry J. Moore Alberta, Canada	Vice President, Engineering	Vice President, Engineering of Journey since July 1, 2012 and previously served as Senior Vice President, Engineering at Sword, the predecessor to Journey.	N/A
Anthony V. Polini Alberta, Canada	Vice President, Land	Vice President, Land of Journey since July 1, 2012 and previously served as the Vice President, Land at Sword, the predecessor to Journey.	N/A

Notes:

(1) Member of the Reserves Committee. Mr. Laustsen is the Chairman of the Reserves Committee.

(2) Mr. Verge was also a director of Sword, the predecessor to Journey. Mr. Verge became a director of Sword on February 11, 2011.

(3) Member of the Audit Committee. Mr. Shay is the Chairman of the Audit Committee.

(4) Member of the Governance & Compensation Committee. Mr. Shay is the Chairman of the Governance & Compensation Committee.

(5) Independent director. Mr. Crone is the Chairman of the Board.

All of the Company's directors' terms of office will expire at the earliest of their resignation, the close of the next annual meeting of Shareholders called for the election of directors, or on such other date as they may be removed according to the ABCA. Each director will devote the amount of time as is required to fulfill his obligations to the Company. The Company's officers are appointed by and serve at the discretion of the Board of Directors.

Directors and Officers – Biographies

The following are brief profiles of the directors and officers of the Company, including a description of each individual's principal occupation within the past five years.

Alex G. Verge – President and Chief Executive Officer and Director

Mr. Verge serves as the President and CEO of Journey. Mr. Verge has more than 30 years of experience in the oil and gas industry and has served as director and Chief Executive Officer and President of NuVista Energy Ltd. from July 2003 to November 2010 and served as a Vice President of Engineering of Bonavista Energy Company and Bonavista Energy Trust (formerly Bonavista Petroleum Ltd.) from January 1998 to June 2003. Prior to joining Bonavista Petroleum Ltd., he worked in the business development group at Poco Petroleums Ltd. and held various engineering positions at Rising Resources, Shell Canada Resources Limited, and Gulf Canada Resources Inc. Mr. Verge is a Member of the Association of Professional Engineers, Geologists & Geophysicists of Alberta. Mr. Verge received a Bachelor of Science degree in Chemical Engineering from the University of Toronto and a Masters of Engineering degree in Chemical and Petroleum Engineering from the University of Calgary.

Howard Crone – Director

Mr. Crone was a director of Cequence Energy from July 2009 until September 28, 2020. From April 9 to July 27th of 2019 Mr. Crone was the interim Chief Financial Officer of Cequence Energy Inc. and was the Executive Vice President and COO from September 2010 to August 2014. Prior thereto, Mr. Crone was the President and CEO of Cequence Energy Ltd. from July 2009 to September 2010. From May 2009 to July 2009, Mr. Crone was President of a privately held oil and gas company. Prior thereto, from July 2004 to May 2009, Mr. Crone was an independent businessman. Prior thereto, from August 2003 to June 2004, Mr. Crone was the Vice President and COO of Cequel Energy Inc., a public oil and gas company. Mr. Crone has been a director of numerous public companies during the past 10 years. Mr. Crone has a Bachelor of Science in Chemical Engineering from the University of Alberta and is also a member of the Association of Professional Engineers and Geoscientists of Alberta.

Dana B. Laustsen – Director

Mr. Laustsen served as Executive Vice President and Chief Operating Officer of GLJ. Mr. Laustsen joined GLJ in 1982 and he later became a principal officer of GLJ in 1994. Mr. Laustsen was employed by Texaco Canada Resources Ltd. for five years where he received his training in petroleum production and reservoir engineering. Mr. Laustsen's background includes detailed reservoir analyses of primary and enhanced recovery projects, SAGD evaluations, ultimate potential studies, merger and acquisition evaluations, fair market value appraisals and expert witness testimony. Mr. Laustsen has co-authored the water flood section of the Petroleum Society of CIMs Monograph, Determination of Oil and Gas Reserves (Monograph No. 1) and is an author of the Canadian Oil and Gas Evaluation Handbook (COGEH) Volume 2 sections on decline analysis and EOR reserve booking guidelines. He has also published articles in the Journal of Canadian Petroleum Technology on decline analysis. Mr. Laustsen graduated from the University of Calgary in 1977 with a Bachelor of Science (Honors) in engineering and is a life member of the Association of Professional Engineers and Geoscientists of Alberta.

Ryan A. Shay– Director

Mr. Shay has in excess of 25 years of experience in the oil and gas industry and was Managing Director, Head of Investment Banking at Cormark Securities Inc. until he retired therefrom in June 2019. Mr. Shay was a member of Cormark's Executive Committee, Risk Committee, Capital Markets Committee, Compensation Committee, Compliance Committee and Audit Committee. Mr. Shay joined Cormark Securities Inc. in 1999 as an energy research analyst and was promoted to the Executive Committee of the firm in 2000. Mr. Shay transitioned careers from research to investment banking in 2007 and was promoted to Co-Head of Investment Banking in 2010 and Head of Investment Banking in 2013. Mr. Shay began his career in the investment industry with Peters & Co. Limited in 1996, earning his Chartered Financial Analyst designation in 1999 and was formerly with Deloitte & Touche in 1993, earning his Chartered Accountant designation in 1996. Mr. Shay received his Bachelor of Commerce from the University of Saskatchewan and graduated with Great Distinction. Mr. Shay also sits on the boards of Perpetual Energy Inc. (since 2017), Crew Energy Inc. (since 2019), and formerly on the National Board of the Juvenile Diabetes Research Foundation (2011 to 2020).

Craig H. Hansen – Director

Mr. Hansen has been the President of Zargon Oil and Gas Ltd. and its predecessor, Zargon Energy Trust, since 1993. Mr. Hansen obtained a B.Sc. (Hons.) in Chemical Engineering from the University of Alberta in 1978 and is a professional engineer registered with APEGGA. Mr. Hansen was employed with Dome Petroleum Ltd. (1978-1980) and NRG Engineering Ltd. (1980-1984). Mr. Hansen founded C.H. Hansen Engineering Ltd., an engineering consulting company, which provided reservoir, exploitation, and acquisition engineering services during the period 1984 through 1993.

Gerald N. Gilewicz – Chief Financial Officer

Mr. Gilewicz has served as the Chief Financial Officer of Journey since September of 2012. Mr. Gilewicz served as Chief Financial Officer and Vice President of Finance at Vero Energy Inc. from November 2005 to August 2012. Previous to that, Mr. Gilewicz served as Vice President of Finance and Chief Financial Officer of Devlan Exploration Inc. from September 1999 to November 2005. Prior to that, Mr. Gilewicz was a Senior Manager at Deloitte & Touche LLP. Mr. Gilewicz is a Chartered Professional Accountant and received his Bachelor of Commerce degree from the University of Saskatchewan.

Brett Boklaschuk – Vice President, Exploration

Since March 2015, Mr. Boklaschuk has served as Vice President, Exploration at Journey. Prior to that, he served as Manager, Business Development and as a Senior Geologist at Journey. In addition, Mr. Boklaschuk has served as a Senior Geologist, Montney at Nuvista Energy from 2008 to 2012. Mr. Boklaschuk also served in progressive senior technical roles at Venturion Natural Resources, Cork Exploration, Burlington Resources and Canadian Hunter Exploration. Mr. Boklaschuk received his Bachelor of Science degree from the University of Saskatchewan in 1995. He has a P.Geol from the Alberta Association of Engineers and Geoscientists of Alberta and is a member of Canadian Society of Petroleum Geologists.

Terry J. Moore – Vice President, Engineering

Mr. Moore serves as Vice President, Engineering of Journey. He previously served as Vice President, Operations and then as Senior Vice President, Engineering at Sword, the predecessor to Journey, from July 2007 to June 2012. Prior to Sword, he held various roles in public companies including Enerplus Resources Fund and private companies including PRL Resources Inc. Mr. Moore has a background in engineering, operations and planning. He received a Bachelor of Applied Science in Mechanical Engineering from the University of Toronto in 1981 and is a member of the Association of Professional Engineers and Geoscientists of Alberta.

Anthony V. Polini – Vice President, Land

Mr. Polini serves as Vice President, Land of Journey. Mr. Polini joined Outrider Energy Ltd. in 2004 and served as its Vice President, Land until early 2009 then continued as Vice President, Land for Vigilant Exploration until the end of 2009. From 1993 to 1997, Mr. Polini worked for PanCanadian Petroleum and Marathon Oil & Gas. Between 1997 and 2004 Mr. Polini served as a Senior Land Negotiator for Koch Petroleum Canada. Mr. Polini is a Senior Oil and Gas Land Negotiator and Acquisition and Divestment Professional and has 26 years of experience and a successful track record in value-added core area growth and asset trading transactions. Mr. Polini received his Bachelor of Commerce, Petroleum Land Management degree at the University of Calgary in 1992, and obtained his Masters of Business Administration from the Consortium Institute of Management and Business Analysis at Clemson University in 1993.

Committees of the Board of Directors

The Company currently has an Audit Committee, a Reserves Committee and a Governance & Compensation Committee.

Share Ownership by Directors and Officers

As a group and as at the date of this AIF, the Company's officers and directors beneficially own or exercise control or direction over, directly or indirectly, 4,916,003 Common Shares, representing approximately 11.2% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of the Company, no director or executive officer of the Company (nor any personal holding company of any of such persons) is, as of the date of this AIF, or was within ten years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including the Company), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

Except for one executive officer that, within the past ten years, voluntarily entered into an arrangement with a creditor (which was not part of any bankruptcy proceeding) with respect to the repayment of certain non-material outstanding amounts, and except as set out below, to the knowledge of the Company no director or executive officer of the Company (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company: (a) is, as of the date of this AIF, or has been within the ten years before the date of this AIF, a director or executive officer of any company (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this 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 the assets of the director, executive officer or Shareholder.

Mr. Crone was a director of Virginia from April 14, 2015 to February 13, 2019. On February 13, 2019 Virginia announced that it had obtained an order from the Court of Queen's Bench of Alberta placing the company into receivership. In addition, Mr. Crone was a director of Cequence Energy Ltd. ("Cequence") from July 2009 to September 28, 2020. On May 29, 2020 Cequence announced that it had obtained an order from the Court of Queen's Bench of Alberta placing the company into CCAA protection.

Mr. Hansen is the President and director of Zargon Oil & Gas Ltd. and its subsidiaries who on September 8, 2020 submitted a Notice of Intention to Make a Proposal to its creditors. The order was approved on January 6, 2021.

Penalties or Sanctions

To the knowledge of the Company, no director or executive officer of the Company (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain officers and directors of the Company are also officers and/or directors of other companies engaged in the oil and gas business generally. As a result, situations may arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of the Company. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate

The Board has adopted a written mandate and terms of reference for the Audit Committee, which sets out the Audit Committee's responsibility for (among other things) reviewing the Company's financial statements and the Company's public disclosure documents containing financial information and reporting on such review to the Board, ensuring the Company's compliance with legal and regulatory requirements, overseeing qualifications, engagement, compensation, performance and independence of the Company's external auditors, and reviewing, evaluating and approving the internal control and risk management systems that are implemented and maintained by management. A copy of the Audit Committee mandate is attached to this AIF as Appendix "C".

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee consists of Messrs. Shay (Chair), Crone and Hansen. Each of the members of the Audit Committee is considered "financially literate" and "independent" within the meaning of NI 52–110.

The Company believes that each of the members of the Audit Committee possesses: (a) an understanding of the accounting principles used by the Company to prepare its financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and provisions;

(c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Company's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting.

For a summary of the education and experience of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee, see "*Directors and Officers*".

Pre-Approval Policies and Procedures for the Engagement of Non–Audit Services

The Audit Committee must pre-approve all non-audit services to be provided to the Company by its 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 the Audit Committee from time to time.

External Audit Service Fees

The following table summarizes the fees paid by the Company to its auditors, KPMG LLP for external audit and other services during the period indicated.

Year	Audit Fees (1)	Audit -Related Fees (2)	Tax Fees	All Other Fees
	($)	($)	($)	($)
2020	100,000	30,000	-	1,500
2019	100,000	30,000	-	-

Notes:

(1) Represents the aggregate fees for services related to the audit of the annual financial statements.

(2) Includes aggregate fees billed for assurance and related services related to the review of the Company's quarterly financial statements.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

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

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as otherwise set out herein, there is no material interest, direct or indirect, of any: (a) director or executive officer of Journey; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of Journey'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 Journey.

TRANSFER AGENT AND REGISTRAR

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

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, are the following:

1. the Credit Agreement;
2. the Second Lien Term Debt Agreement
3. the Promissory Notes (2016);
4. the Promissory Notes (2018);
5. the Second Lien Term Debt (September 30, 2019), and
6. the Amended and Restated Senior Secured Credit Agreement (October 30, 2020).

Copies of the foregoing may be viewed on the SEDAR website at www.sedar.com.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 - *Continuous Disclosure Obligations* by us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator and KPMG LLP, our current external auditors. As at the date hereof, none of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of Journey or of our associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. The Corporation's independent auditors are KPMG LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated March 9, 2021 in respect of the Corporation's consolidated financial statements as at December 31, 2020 and 2019 and for the years then ended. KPMG LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct with Guidance of the Chartered Professional Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Journey or of any associate or affiliate of Journey.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on the SEDAR website at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans, if applicable, will be contained in the Company's management proxy circular which is expected to be dated in April 2021 relating to the annual general meeting of Shareholders to be held on May 26, 2021. Additional financial information is provided in the financial statements and management's discussion and analysis of the Company for the year ended December 31, 2020, which are accessible on the SEDAR website at www.sedar.com.

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

To the board of directors of Journey Energy Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, 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 for the year ended December 31, 2020, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $000s)			
			Audited	**Evaluated**	**Reviewed**	**Total**
GLJ Ltd.	December 31, 2020	Canada	–	245,118	–	**245,118**

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 reports.

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

Executed as to our report referred to above:

GLJ Ltd.
Calgary, Alberta, Canada,
March 9, 2021

"Original Signed By" "Trevor J. Rix"
Manager, Engineering

APPENDIX "B"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Journey Energy Inc. ("**Journey**") is responsible for the preparation and disclosure of information with respect to Journey's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data and resources data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020 estimated using forecast prices and costs.

An independent qualified reserves evaluator has audited, evaluated and reviewed and reported on Journey's reserves data. The reports of the independent qualified reserves evaluator is presented below.

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

- reviewed Journey's procedures for providing information to the independent qualified reserves evaluator;
- 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
- reviewed the reserves data and resources data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed Journey'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

- the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- the content and filing of this report.

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

(signed) "*Alex G. Verge*"
Alex G. Verge
President and Chief Executive Officer

(signed) "*Dana B. Laustsen*"
Dana B. Laustsen
Director, and Chairman of the Reserves Committee

(signed) "*Terry Moore*"
Terry Moore
Vice President, Engineering

(signed) "*Howard Crone*"
Howard Crone
Director and member of the Reserves Committee

March 23, 2021

APPENDIX "C"
AUDIT COMMITTEE MANDATE

JOURNEY ENERGY INC.
MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Journey Energy Inc. ("**Journey**" or the "**Company**") to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Journey and related matters;

2. To provide better communication between directors and external auditors;

3. To enhance the external auditor's independence;

4. To increase the credibility and objectivity of financial reports; and

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

Membership of Committee

1. The Committee will be comprised of at least three (3) directors of Journey or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 — Audit Committees unless the Board determines that the exemption contained in NI 52 110 is available and determines to rely thereon.

2. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.

3. All of the members of the Committee must be "financially literate" (as defined in NI 52 110) unless the Board determines that an exemption under NI 52 110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52 110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Journey's internal control systems:

    - identifying, monitoring and mitigating business risks; and

    - ensuring compliance with legal, ethical and regulatory requirements.

3. Review the annual and interim financial statements of Journey and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

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

- reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

- reviewing accounting treatment of unusual or non-recurring transactions;

- ascertaining compliance with covenants under loan agreements;

- reviewing disclosure requirements for commitments and contingencies;

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

- reviewing unresolved differences between management and the external auditors; and

- obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Journey's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board:

- recommend to the Board the external auditors to be nominated;

- recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;

- on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Company to determine the auditors' independence;

- when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

- review and pre approve any non-audit services to be provided to Journey or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by Journey) their assessment of the internal controls of Journey, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Journey and its subsidiaries.

7. Review risk management policies and procedures of Journey (e.g. hedging, litigation and insurance).

8. Establish a procedure for:

- the receipt, retention and treatment of complaints received by Journey regarding accounting, internal accounting controls or auditing matters; and
- the confidential, anonymous submission by employees of Journey of concerns regarding questionable accounting or auditing matters.

9. Maintain and administer the Company's "whistleblower" policy.

10. Review and approve Journey's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Journey.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Company. The Committee will also have the authority to investigate any financial activity of Journey. All employees of Journey are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Journey without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Company as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Company.

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies

on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.