



ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2020

March 10, 2021

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SCHEDULES

SCHEDULE "A" – FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR	
SCHEDULE "B" – FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE	
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ABOUT TOURMALINE

Tourmaline is an investment grade Canadian senior crude oil and natural gas exploration and production company. It is focused on providing strong and predictable long-term growth and a steady return to shareholders through an aggressive exploration, development, production and acquisition program in the Western Canadian Sedimentary Basin by building its extensive asset base in its three core exploration and production areas and exploiting and developing these areas to increase reserves, production and cash flows at an attractive return on invested capital. It is also Canada's largest natural gas producer with a strong commitment to environmental, social and governance best practices.

CONVENTIONS

Unless otherwise indicated, any reference in this Annual Information Form to "**Tourmaline**", the "**Company**" or the "**Corporation**" means Tourmaline Oil Corp. Certain other terms used but not defined herein are defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**"), in the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter) (the "**COGE Handbook**"), in the Canadian Securities Administrators Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* and under the heading "*Selected Abbreviations*" herein. Unless otherwise specified, information in this Annual Information Form is as at the end of the Company's most recently completed financial year, being December 31, 2020. All dollar amounts herein are in Canadian dollars, unless otherwise stated. See "*Selected Abbreviations*", "*Selected Conversions*", "*Forward-Looking Statements*" and "*Certain Reserves Data Information*". Certain portions of Tourmaline's audited consolidated financial statements ("**Financial Statements**") and Management's Discussion and Analysis ("**MD&A**") for the year ended December 31, 2020 are incorporated by reference into this Annual Information Form as indicated herein. The Financial Statements and MD&A are available on SEDAR at www.sedar.com. All references in this Annual Information Form to management are to the persons who are identified in this Annual Information Form as the executive officers of the Company. See "*Directors and Officers*". All statements in this Annual Information Form made by or on behalf of management are made in such persons' capacities as executive officers of the Company and not in their personal capacities. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

CORPORATE STRUCTURE

Name, address and incorporation

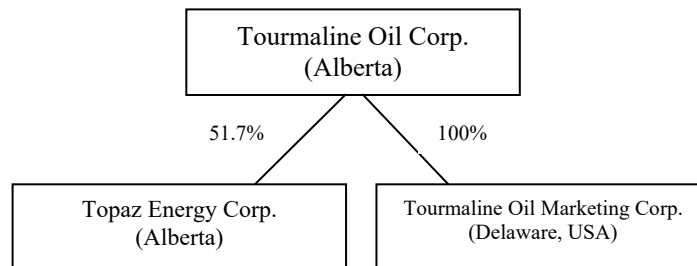
Tourmaline Oil Corp. was incorporated under the *Business Corporations Act* (Alberta) (the "**ABCA**") under the name "1415065 Alberta Ltd." on July 21, 2008. On August 26, 2008, Tourmaline filed Articles of Amendment to change its name to "Tourmaline Oil Corp.". On October 24, 2008, Tourmaline filed Articles of Amendment to: (i) create a new class of shares designated as first preferred shares (the "**First Preferred Shares**"), issuable in series, and a new class of shares designated as second preferred shares (the "**Second Preferred Shares**"), issuable in series, and amend the terms of the common shares (the "**Common Shares**"); (ii) remove the "private company" restrictions; and (iii) change the minimum number of directors of the Company from one to three. Tourmaline amalgamated with its wholly-owned subsidiaries Pienza Petroleum Inc. ("**Pienza**") and Vigilant Exploration Inc. ("**Vigilant**") on January 1, 2010, amalgamated with its wholly-owned subsidiary Altia Energy Ltd. ("**Altia**") on January 1, 2011, amalgamated with its wholly-owned subsidiary Cinch Energy Corp. ("**Cinch**") on January 1, 2012, amalgamated with its wholly-owned subsidiary Huron Energy Corporation ("**Huron**") on January 1, 2013, amalgamated with its wholly-owned subsidiary Santonia Energy Inc. ("**Santonia**") on January 1, 2015, amalgamated with its wholly-owned subsidiaries Bergen Resources Inc. ("**Bergen**") and Mapan Energy Ltd. ("**Mapan**") on January 1, 2016, amalgamated with its wholly-owned subsidiaries Polar Star Canadian Oil and Gas, Inc. ("**Polar Star**"), Chinook Energy Inc. ("**Chinook**"), Modern Resources Inc. ("**Modern**"), and Jupiter Resources Inc. ("**Jupiter**") on January 1, 2021, in each case continuing as Tourmaline Oil Corp.

Tourmaline's head office is located at Suite 3700, 250 – 6th Avenue S.W., Calgary, Alberta T2P 3H7 and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Intercorporate relationships

The Company has no subsidiaries in which the assets and revenues of such subsidiaries exceed 10% individually, or 20% in the aggregate, of the total consolidated assets or total consolidated revenues of the Company as at and for the year ended December 31, 2020.

The following diagram illustrates the intercorporate relationship between Tourmaline and its subsidiaries, the percentage of votes attached to all voting securities of the subsidiaries beneficially owned, or controlled or directed, directly or indirectly, by Tourmaline and the jurisdiction of incorporation of the subsidiaries.



DESCRIPTION OF THE BUSINESS

Overview

Tourmaline is an investment grade Canadian senior crude oil and natural gas exploration and production company focused on providing strong and predictable long-term growth and a steady return to shareholders through an aggressive exploration, development, production and acquisition program in the Western Canadian Sedimentary Basin ("WCSB"). Tourmaline commenced active operations in the fall of 2008 with the objective of building a successful Canadian crude oil and natural gas exploration, development and production company with a long-term business strategy similar to that of Duvernay Oil Corp. ("Duvernay") and Berkley Petroleum Corp. ("Berkley"), companies previously founded and managed by certain key members of Tourmaline's senior management team. Through a series of strategic acquisitions, farm-ins, joint ventures and land acquisitions combined with its active capital exploration and development program, Tourmaline has increased current production to over 400,000 Boe/d. The Company has assembled an extensive undeveloped land position with a large, multi-year drilling inventory and operating control of important natural gas processing and transportation infrastructure in three core long-term growth areas – the Alberta Deep Basin, NEBC Montney and the Peace River High Triassic Oil Complex.

To date, the Company has raised approximately \$4.0 billion through private placement equity financings and public offerings, approximately \$375.2 million of which was raised from Tourmaline's directors, officers, employees and their associates, and strategically completed a number of acquisitions to cost-effectively build its current production and extensive land position. The acquisitions have complemented an aggressive exploration, development and production program that is intended to be the Company's primary long-term growth engine.

Management believes that the location, size, concentration and other attributes of the Company's three core long-term growth areas provide an opportunity for the Company to achieve operating cost, reserve recovery, deliverability and production efficiencies through a large-scale, repeatable capital exploration and development program. Tourmaline is aggressively executing this program using principally 3D seismic data to identify drilling locations for multi-stage fracture stimulations of vertical and horizontal wells. A key component of Tourmaline's long-term business strategy has always been to be one of the lowest cost operators within its core areas.

Business Strategy

Tourmaline's long-term business strategy is to increase shareholder value by providing both strong and predictable long-term growth and a steady return to shareholders through an aggressive exploration, development, production and acquisition program in the WCSB by building its extensive asset base in its three core exploration

and production areas and exploiting and developing these areas to increase reserves, production and cash flows at an attractive return on invested capital. The Company seeks to execute this strategy by: aggressively drilling and developing its extensive undeveloped land position; adopting and employing advanced drilling and completion techniques; pursuing strategic acquisitions with significant potential synergies; undertaking wildcat exploration drilling for new pool discoveries and enhancing returns by focusing on operational and cost efficiencies. The Company strives to be one of the lowest cost producers in the WCSB in order to accomplish its business strategy in any economic and commodity price environment.

General Development of the Business

2018

On March 6, 2018, the Board of Directors of the Company (the "**Board**") declared its first quarterly dividend of \$0.08 per Common Share payable on March 29, 2018 to shareholders of record on March 14, 2018.

On May 8, 2018, the Board increased the Company's quarterly dividend by 12.5% to \$0.09 per Common Share.

On May 15, 2018, Tourmaline completed a private placement of 1,000,000 "flow-through" Common Shares at a price of \$30.00 per Common Share for aggregate gross proceeds of approximately \$30.0 million.

On August 1, 2018, the Board increased the Company's quarterly dividend by an additional 11% to \$0.10 per Common Share.

2019

On May 8, 2019, the Board increased the Company's quarterly dividend by 20% to \$0.12 per Common Share.

On October 31, 2019, Tourmaline purchased the 9.4% minority interest in Exshaw Oil Corp, ("**Exshaw**"), resulting in Exshaw becoming a wholly-owned subsidiary of Tourmaline. Subsequently, in early November 2019, Tourmaline purchased the entirety of Exshaw's oil and gas assets and Exshaw's name was changed to "Topaz Energy Corp." ("**Topaz**").

On November 14, 2019, Tourmaline and Topaz completed a transaction which resulted in the formation of Topaz, a unique, private, hybrid royalty and infrastructure company, whereby Topaz purchased from Tourmaline certain revenue-generating oil and gas assets, which provide Topaz with the following three separate revenue streams (collectively, the "**Revenue Streams**"):

- (1) a gross overriding royalty on natural gas, oil and condensate production on 100% of Tourmaline's then-existing lands (approximately 2.2 million net acres);
- (2) a non-operated 45% working interest in two natural gas processing plants underpinned by long-term take-or-pay commitments from Tourmaline; and
- (3) a contracted interest in a portion of certain third-party revenues generated by natural gas processing and handling agreements.

Consideration paid to Tourmaline by Topaz consisted of \$194.5 million in cash and 59.1 million Topaz common shares. The cash portion of the purchase consideration was funded by a private placement to investors of 20.9 million Topaz common shares at a price of \$10.00 per share.

2020

In the first half of 2020 Tourmaline completed two small corporate acquisitions further consolidating its key land holdings and infrastructure in its NEBC Montney core area with its acquisition of Polar Star on February 14, 2020 and Chinook on April 21, 2020. On a combined basis, the acquired assets included approximately 6,000 Boe/d of production, proved plus probable reserves of 116.3 MMboe (as evaluated by independent reserve evaluators at December 31, 2018), 160,000 net acres of Montney land, two compressor stations, and a 190 mmcfpd regional 12-inch pipeline.

In 2020, Tourmaline also completed several small acquisitions in the Alberta Deep Basin complex, which added an aggregate of approximately 3,200 Boe/d of production, 32 MMboe of proved plus probable reserves (as evaluated by McDaniel & Associates Consultants Ltd as at December 31, 2019), 67 net sections of land, and a gas plant interest.

On September 9, 2020, Tourmaline was assigned an issuer credit rating of BBB with a stable trend from DBRS Limited ("DBRS"). This public investment grade credit rating validated the overall financial health of Tourmaline as a stable, low-risk, senior North American oil and gas producer. The Company believes that an investment grade rating will provide confidence to the market to effectively and efficiently evaluate and assess credit risk as well as help in obtaining and managing debt on favourable terms and provide for better benchmarking comparisons.

During the third quarter of 2020, Tourmaline sold 25% of the Company's Banshee gas plant in the Alberta Deep Basin to Topaz for cash proceeds of \$52.5 million. The sale provides Topaz with a take-or-pay commitment of 25 MMcf/d at \$0.60/mcf for a 15-year term. Topaz pays its share of operating costs and annual maintenance costs at the Banshee plant.

On October 26, 2020, Topaz successfully completed its initial public offering and Tourmaline sold 1.0 million Topaz common shares in connection with the offering at a price of \$13.00 per share ("the **Secondary Offering**") for total gross proceeds of \$13.0 million. After giving effect to the Topaz offering, including the subsequent exercise by the underwriters of the over-allotment option, and the Secondary Offering, Tourmaline owns 58.1 million Topaz common shares which had a market value of \$790.8 million as December 31, 2020. This represents an ownership interest of 51.7% and a non-controlling interest of 48.3% at December 31, 2020.

On November 2, 2020, Tourmaline closed the acquisition of Modern for total consideration of approximately \$99.3 million (comprised of \$73.75 million cash and 1.5 million Tourmaline common shares) plus the assumption of net debt. At the time of acquisition, the acquired assets included approximately 9,000 Boe/d of production, 88 MMboe of proved plus probable reserves (as internally estimated by qualified reserve engineers as at August 31, 2020), over 400 sections of land, and a gas plant.

On November 4, 2020, the Board increased the Company's quarterly dividend by 17% to \$0.14 per Common Share.

On December 18, 2020, Tourmaline closed the acquisition of Jupiter for total common share consideration of \$418.9 million (comprised of 24.2 million Tourmaline common shares) plus the assumption of net debt. At the time of acquisition, the acquired assets included approximately 67,000 Boe/d of production, 357 MMboe of proved plus probable reserves (as evaluated by GLJ Ltd. as at December 31, 2019), over 500 sections of land, and working interests in three gas plants.

Potential Acquisitions and Financings

Tourmaline continues to evaluate potential acquisitions of all types of petroleum and natural gas and other energy-related assets and/or companies as part of its ongoing acquisition program. Tourmaline is regularly in the process of evaluating several potential acquisitions at any one time, which individually or together could be material. Tourmaline cannot predict whether any current or future opportunities will result in one or more acquisitions for Tourmaline. In addition, Tourmaline may, in the future, complete financings of equity or debt (which may be convertible into equity) for purposes that may include financing of acquisitions, Tourmaline's operations and capital expenditures and repayment of indebtedness.

Acquisition Summary

The following table summarizes the Company's key acquisitions since inception.

Acquisition Summary

Date	Acquisition	Areas	Purchase Price (MMS) ⁽¹⁾	Production ⁽²⁾ (Boe/d)	Undeveloped Land	
					Gross Acres	Net Acres
April 30, 2009.....	Alberta Deep Basin acquisition	Hinton/Musreau/Narraway	\$103.0	2,350	86,072	27,466
August 28, 2009.....	Wild River acquisition	Wild River/Harley/Olsen/Sundance	\$145.9	2,550	44,196	24,016
September 15, 2009....	Pienza acquisition ⁽³⁾	Sunrise NEBC	\$50.0	350	23,348	15,980
November 10, 2009....	Exshaw acquisition	Peace River Arch	\$131.8	2,510	56,960	41,718
November 10, 2009....	Vigilant acquisition ⁽³⁾	Musreau/Chime/Whitecourt	\$47.5	650	92,734	88,538
January 14, 2010.....	Altia acquisition ⁽⁴⁾	Dawson NEBC	\$100.8	1,500	122,600	56,980
June 1, 2010.....	Greater Hinton acquisition	Greater Hinton	\$275.0	4,000	266,849	204,560
July 12, 2011.....	Cinch acquisition ⁽⁵⁾	Dawson/Musreau-Kakwa	\$211.1	3,700	134,274	87,580
November 30, 2012....	Huron acquisition ⁽⁶⁾	Groundbirch/Sunrise/Tupper	\$245.4	5,500	84,405	55,766
April 24, 2014.....	Santonia acquisition ⁽⁷⁾	Wilrich/Notikewin/Viking/Falher/Cardium	\$177.4	3,800	158,671	92,364
April 1, 2015.....	Perpetual acquisition	West Edson	\$258.7	5,750	37,760	18,581
July 20, 2015.....	Bergen acquisition ⁽⁸⁾	Mulligan	\$24.6	500	57,760	27,253
August 14, 2015.....	Mapan acquisition ⁽⁹⁾	Chinook Ridge/Berland/Cecilia/Bigstone	\$89.6	5,500	216,916	166,898
January 29, 2016.....	Alberta Deep Basin acquisition	Minehead/Edson/Ansell	\$183.0	4,750	80,320	55,129
November 30, 2016....	Shell Canada acquisition	Alberta Deep Basin/Gundy NEBC	\$1,367.8	24,850	256,035	185,789
August 13, 2019.....	Peace River Re-acquisition	Peace River High	\$175.0	5,600	-	82,544
October 31, 2019.....	NEBC acquisition	Gundy NEBC	\$49.0	-	11,413	8,559
February 14, 2020.....	Polar Star acquisition ⁽¹⁰⁾	Montney NEBC	\$12.0	2,500	163,580	146,893
April 21, 2020.....	Chinook acquisition ⁽¹⁰⁾	Montney NEBC	\$15.1	3,500	100,698	60,784
April 1, 2020.....	Alberta Deep Basin acquisition	East Edson	\$35.0	3,200	16,640	13,156
November 2, 2020.....	Modern acquisition ⁽¹⁰⁾	Musreau/Kakwa	\$99.3	9,000	244,166	201,820
December 18, 2020.....	Jupiter acquisition ⁽¹⁰⁾	Musreau/Resthaven/Kakwa	\$418.9	67,000	185,286	165,231
			\$4,215.9	159,060	2,440,683	1,827,605

Notes:

- (1) These amounts reflect the purchase price paid in cash and/or Common Shares.
- (2) Estimated production as at the effective date of the acquisition.
- (3) Subsequent to the Pienza and Vigilant acquisitions, Tourmaline amalgamated with Pienza and Vigilant on January 1, 2010 under the ABCA, continuing as Tourmaline Oil Corp.
- (4) Subsequent to the Altia acquisition, Tourmaline amalgamated with Altia on January 1, 2011 under the ABCA, continuing as Tourmaline Oil Corp.
- (5) Subsequent to the Cinch acquisition, Tourmaline amalgamated with Cinch on January 1, 2012 under the ABCA, continuing as Tourmaline Oil Corp.
- (6) Subsequent to the Huron acquisition, Tourmaline amalgamated with Huron on January 1, 2013 under the ABCA, continuing as Tourmaline Oil Corp.
- (7) Subsequent to the Santonia acquisition, Tourmaline amalgamated with Santonia on January 1, 2015 under the ABCA, continuing as Tourmaline Oil Corp.
- (8) Subsequent to the Bergen acquisition, Tourmaline amalgamated with Bergen on January 1, 2016 under the ABCA, continuing as Tourmaline Oil Corp.
- (9) Subsequent to the Mapan acquisition, Tourmaline amalgamated with Mapan on January 1, 2016 under the ABCA, continuing as Tourmaline Oil Corp.
- (10) Subsequent to the Polar Star, Chinook, Modern, and Jupiter acquisitions, Tourmaline amalgamated with Polar Star, Chinook, Modern, and Jupiter on January 1, 2021 under the ABCA, continuing as Tourmaline Oil Corp.

Summary of Equity Financings

The following table summarizes the equity financings completed by the Company since commencement of active operations as well as Company insider, employee and associate participation in such equity financings.

Summary of Equity Financings

Date	Financings		Insider, Employee and Associate Participation ⁽²⁹⁾	
	Shares Issued	Total Gross Proceeds	Gross Subscriptions	Percentage of Gross Proceeds
October 27, 2008	50,500,000 ⁽¹⁾	\$301,000,000	\$147,000,000	48.8%
December 17, 2008.....	2,500,000 ⁽²⁾	\$25,000,000	\$12,500,000	50.0%
May 28, 2009	14,000,000 ⁽³⁾	\$140,000,000	\$30,000,000	21.4%
November 10, 2009	13,543,624 ⁽⁴⁾	\$208,404,360	\$47,904,360	23.0%
March 19, 2010.....	11,950,000 ⁽⁵⁾	\$223,920,000	\$36,720,000	16.4%
August 12, 2010.....	1,150,000 ⁽⁶⁾	\$25,300,000	\$6,600,000	26.1%
November 23, 2010	12,350,000 ⁽⁷⁾	\$259,350,000	\$17,850,000	6.9%
March 8, 2011.....	1,580,000 ⁽⁸⁾	\$47,400,000	\$11,400,000	24.1%
May 17, 2011.....	6,825,000 ⁽⁹⁾	\$174,037,500	\$12,750,000	7.3%
October 12, 2011	4,900,000 ⁽¹⁰⁾	\$161,700,000	\$9,900,000	6.1%
December 1, 2011.....	1,361,500 ⁽¹¹⁾	\$55,821,500	\$6,621,500	11.9%
April 4, 2012.....	1,402,000 ⁽¹²⁾	\$40,377,600	\$4,377,600	10.8%
August 30, 2012.....	4,639,000 ⁽¹³⁾	\$134,531,000	\$1,131,000	0.8%
November 1, 2012	1,050,000 ⁽¹⁴⁾	\$38,745,000	\$1,845,000	4.8%
March 12, 2013.....	6,615,000 ⁽¹⁵⁾	\$233,160,250	\$4,610,250	2.0%
October 8, 2013	4,420,000 ⁽¹⁶⁾	\$193,646,250	\$5,748,750	3.0%
February 12, 2014.....	4,615,198 ⁽¹⁷⁾	\$219,221,905	\$721,905	0.3%
June 2, 2014.....	1,150,000 ⁽¹⁸⁾	\$78,372,500	\$8,314,300	10.6%
November 28, 2014	280,053 ⁽¹⁹⁾	\$15,963,021	Nil	Nil
March 12, 2015.....	640,000 ⁽²⁰⁾	\$32,000,000	Nil	Nil
June 23, 2015.....	4,947,500 ⁽²¹⁾	\$195,426,250	\$2,133,000	1.1%
November 25, 2015	482,700 ⁽²²⁾	\$16,460,070	Nil	Nil
April 5, 2016.....	10,387,500 ⁽²³⁾	\$281,605,125	\$1,016,625	0.4%
May 17, 2016.....	1,320,000 ⁽²⁴⁾	\$46,860,000	Nil	Nil
October 20, 2016	890,500 ⁽²⁵⁾	\$39,627,250	Nil	Nil
November 10, 2016	21,758,700 ⁽²⁶⁾	\$756,114,825	\$6,081,250	0.8%
December 5, 2017.....	1,300,000 ⁽²⁷⁾	\$40,560,000	Nil	Nil
May 15, 2018.....	1,000,000 ⁽²⁸⁾	\$30,000,000	Nil	Nil
	187,558,275	\$4,014,604,406	\$375,225,540	9.3%

Notes:

- (1) Private placement of 15,000,000 Common Shares at \$3.50 per share and 35,500,000 Common Shares at \$7.00 per share.
- (2) Private placement of 2,500,000 flow-through Common Shares at \$10.00 per share.
- (3) Private placement of 14,000,000 Common Shares at \$10.00 per share.
- (4) Private placement of 11,793,624 Common Shares at \$15.00 per share and 1,750,000 flow-through Common Shares at \$18.00 per share.
- (5) Private placement of 9,500,000 Common Shares at \$18.00 per share and 2,450,000 flow-through Common Shares at \$21.60 per share.
- (6) Private placement of 1,150,000 flow-through Common Shares at \$22.00 per share.
- (7) Initial public offering of 12,350,000 Common Shares at \$21.00 per share which includes the issuance of 1,500,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option (completed on December 23, 2010) and 850,000 Common Shares issued pursuant to a concurrent private placement to certain executive officers.
- (8) Private placement of 1,580,000 flow-through Common Shares at \$30.00 per share.
- (9) Public offering of 6,825,000 Common Shares at \$25.50 per share which includes the issuance of 825,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option and 500,000 Common Shares issued pursuant to a concurrent private placement to certain executive officers.
- (10) Public offering of 4,900,000 Common Shares at \$33.00 per share which includes the issuance of 600,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option (completed on October 19, 2011) and 300,000 Common Shares issued pursuant to a concurrent private placement to certain executive officers.
- (11) Public offering of 1,361,500 flow-through Common Shares at \$41.00 per share which includes 161,500 Common Shares issued pursuant to a concurrent private placement to certain executive officers.

- (12) Public offering of 1,250,000 flow-through Common Shares at \$28.80 per share and a concurrent private placement of 152,000 flow-through Common Shares of which 94,000 flow-through Common Shares were issued to certain executive officers.
- (13) Public offering of 4,600,000 Common Shares at \$29.00 per share which includes the issuance of 600,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option and a concurrent private placement of 39,000 Common Shares of which 37,000 Common Shares were issued to certain executive officers.
- (14) Public offering of 1,000,000 flow-through Common Shares at \$36.90 per share and a concurrent private placement of 50,000 flow-through Common Shares of which 16,000 flow-through Common Shares were issued to certain executive officers.
- (15) Public offering of 5,750,000 Common Shares at \$34.25 per share which includes the issuance of 750,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option and 750,000 flow-through Common Shares at \$42.15 per share. Concurrent with the public offering was a private placement of 30,000 Common Shares and 85,000 flow-through Common Shares of which 30,000 Common Shares and 17,000 flow-through Common Shares were issued to certain executive officers.
- (16) Public offering of 3,450,000 Common Shares at \$41.75 per share which includes the issuance of 450,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option and 850,000 flow-through Common Shares at \$51.60 per share. Concurrent with the public offering was a private placement of 45,000 Common Shares and 75,000 flow-through Common Shares of which 40,000 Common Shares and 27,100 flow-through Common Shares were issued to certain executive officers.
- (17) Public offering of 4,600,000 Common Shares at \$47.50 per share which includes the issuance of 600,000 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option. Concurrent with the public offering was a private placement of 15,198 Common Shares of which 10,000 were issued to certain executive officers.
- (18) Private placement of 1,150,000 flow-through Common Shares at \$68.15 per share.
- (19) Private placement of 280,053 flow-through Common Shares at \$57.00 per share.
- (20) Private placement of 640,000 flow-through Common Shares at \$50.00 per share.
- (21) Public offering of 4,887,500 Common Shares at \$39.50 per share which includes the issuance of 637,500 Common Shares issued pursuant to the exercise of the underwriters' over-allotment option. Concurrent with the public offering was a private placement of 60,000 Common Shares of which 54,000 Common Shares were issued to certain executive officers.
- (22) Private placement of 482,700 flow-through Common Shares at \$34.10 per share.
- (23) Public offering of 10,350,000 Common Shares at \$27.11 per share. Concurrent with the public offering was a private placement of 37,500 Common Shares of which 33,000 were issued to certain executive officers.
- (24) Private placement of 1,320,000 "flow-through" Common Shares at \$35.50 per share.
- (25) Private placement of 890,500 "flow-through" Common Shares at \$44.50 per share.
- (26) Public offering of 3,309,700 subscription receipts at \$34.75 per receipt. Concurrent with the public offering was a private placement of 18,449,000 subscription receipts at \$34.75 per receipt, including a non-brokered offering of 175,000 subscription receipts at \$34.75 per receipt, of which 88,000 subscription receipts were issued to certain executive officers. All subscription receipts were subsequently converted to Common Shares on November 30, 2016 on a one-to-one basis.
- (27) Private placement of 1,300,000 flow-through Common Shares at \$31.20 per share.
- (28) Private placement of 1,000,000 flow-through Common Shares at \$30.00 per share.
- (29) Represents percentage of insider, employee and associate participation for the total amount raised by the Company, which has been calculated based on the percentage of Common Shares issued to directors, officers, employees and other service providers of the Company and certain family, friends and business associates of the foregoing relative to the total number of Common Shares issued in each financing.

DESCRIPTION OF CORE LONG-TERM GROWTH AREAS

The following is a description of Tourmaline's three core long-term growth areas – the "**Alberta Deep Basin**" includes the area within the WCSB from Edmonton, Alberta to approximately 400 km west, "**NEBC Montney**" includes the area extending from Grande Prairie, Alberta to approximately 175 km northwest of Fort St. John, British Columbia, and the "**Peace River High Triassic Oil Complex**" spans from 125 km north of Grande Prairie, Alberta to 60 km south of Grande Prairie, Alberta and includes the Wapiti Cardium area.

Alberta Deep Basin Core Area

The Alberta Deep Basin core area is a multi-objective tight natural gas sand play area with up to fifteen separate lower Cretaceous liquids-rich natural-gas-charged sand reservoirs. Tourmaline's target exploration and production area is in that portion of the Alberta Deep Basin where the entire lower Cretaceous stratigraphic section is gas saturated with no mobile formation water. The primary vehicle for accessing the extensive reserves in these stacked sandstones is multi-stage fracture stimulation in both horizontal and vertical well-bores. Tourmaline utilizes 3D seismic data to select the majority of its drilling locations, and management believes it is an industry leader in

adopting and continually adapting the improving drilling and completion technologies. These two factors allow the Company to consistently deliver a significant portion of the highest productivity gas wells in the province with amongst the lowest completed well costs on an annual basis. The majority of the Company's working interest lands have already received approval for down-spacing at four wells per section per zone or formation or reservoir.

Certain formations within the lower Cretaceous stack of tight sand reservoirs in the Alberta Deep Basin are more amenable to horizontal drilling (including the Cardium, Viking, Wilrich, Fahler and Notikewin formations). Accordingly, each section in the Alberta Deep Basin core area is expected to include on average two to three targeted multi-stage stimulated horizontal wells in the Company's long-term development plan. Management estimates that up to 9,683 gross horizontal drilling locations exist on its Alberta Deep Basin holdings which are currently being assessed as part of the ongoing drilling program. These horizontal drilling locations have been included in the Company's development drilling inventory. Future evaluation of these multiple resource plays is an important component of the 2021 capital exploration and development program, with approximately 100 gross horizontal wells currently planned. Tourmaline has been targeting the more condensate and NGL rich formations (Cardium, Viking and Fahler) with horizontal drilling over the past two years. In addition, the Company has 3,876 vertical development locations, including 450 gross outer foothills thrust belt vertical wells with geologic and economic parameters similar to those of the horizontal inventory.

Tourmaline currently has ownership interests in fifteen natural gas plants in the Alberta Deep Basin, eight of which (the Wild River 14-20, the Hinton 6-32, the Anderson 1-9, the Cecilia 15-04, the Edson 4-17, the Route 7-09, the Oldman 10-24 and the Sundance 15-7) are 100% owned and operated by Tourmaline. In aggregate, Tourmaline has in excess of 1.5 Bcf/d of natural gas processing capability within this plant network. Tourmaline's goal is to be one of the lowest-cost, most efficient operators in the Alberta Deep Basin, and the Company plans to optimize and systematically continue to further reduce costs of operating the Alberta Deep Basin assets.

Since inception, Tourmaline has drilled approximately 890 gross natural gas wells in the Alberta Deep Basin and intends to drill approximately 100 additional gross wells in 2021. Tourmaline is the largest producer in the Alberta Deep Basin with production currently estimated at approximately 250,000 Boe/d. The Company's landholdings in the core area are approximately 3,681 gross sections. Year-end 2020 proved plus probable reserves were 1,474.9 MMboe in the Alberta Deep Basin, with approximately 948 gross (853.6 net) future drilling locations recognized in the Consolidated Reserve Report (as defined herein).

NEBC Montney

Tourmaline's second core exploration and production area on the west flank of the Peace River High in NEBC is focused on liquids rich natural gas in the Triassic Montney formation. Industry participants have been pursuing Triassic Montney plays and reservoirs in the WCSB for over four decades. Exploration and production of the Montney has evolved over time from conventional reservoirs pursued with vertical wells in the south east portion of the play area in Alberta to unconventional Montney reservoirs in the Peace River Arch area of Alberta and NEBC. Technological developments, including the drilling of horizontal multi-stage fracture stimulation wells, have allowed access to the thickest, highest pressured and highest deliverability fine grained sandstone reservoirs of the Montney in the NEBC play area. It is in the Groundbirch/Sunrise/Dawson area of the Peace River Arch where senior management of Tourmaline gained extensive experience with Duvernay Oil Corp. and where Tourmaline concentrated its initial Montney exploration and production program.

The Company has assembled its large Montney position primarily through multiple acquisitions completed between 2009 and 2020. Late in 2016, the Company completed the largest property acquisition in the Company's history which included a new property in NEBC, adding 6,200 Boe/d of initial production, over 100 sections of land and 1,600 new Montney drilling locations in the Gundy CK area, which is northwest of the Company's existing Sunrise/Dawson/Sundown complex. Both the original Sunrise/Dawson complex and Gundy CK contain liquid-rich sweet gas in the Montney, allowing for lower, long-term operating costs compared to the majority of Montney focused competitors pursuing sour gas. In NEBC, Tourmaline has an inventory of approximately 4,393 gross horizontal Montney development drilling locations, making the Company one of the largest participants in this resource play. To date, Tourmaline has drilled approximately 560 Montney multi-stage fracture-stimulated horizontal natural gas wells in NEBC with an additional approximately 115 gross Montney horizontal wells planned for 2021. Tourmaline's 2021 – 2022 two year development plan for the Gundy CK Montney asset includes

continuing to apply drilling and completion practices developed in the Groundbirch/Sunrise/Dawson area in order to continue to reduce development costs, improve efficiencies and raise estimated ultimate recoveries (EUR). Tourmaline has amongst the lowest Montney drill and complete capital costs in the industry.

Complementing this growing Montney drilling inventory in NEBC is a series of high-deliverability/low-operating cost, sweet Mississippian, Kiskatinaw and Wabamun natural gas pools. Management believes that these deeper pools also have considerable exploration and production potential and will be the subject of ongoing exploration and development, the ultimate timing of which is dependent on a natural gas price recovery. Tourmaline owns and operates five significant natural gas processing facilities with aggregate capacity of approximately 470 MMcf/d with related gas gathering systems and NGL handling infrastructure in the NEBC complex. This infrastructure complex includes a 200 MMcf/d ethane rejection deep cut gas processing facility installed at Gundy CK in 2019. To further support the Company's development plans in the area, Tourmaline is also planning an additional 200 MMcf/d expansion of the Gundy facility for early 2022. Current production in the NEBC Montney complex is approximately 625-650 MMcf/d of natural gas and a combined 30,000 bbls per day of associated natural gas liquids ("NGLs"), condensate and crude oil. As at December 31, 2020, Tourmaline holds approximately 655 gross sections of Montney rights in NEBC with 1,578.1 MMboe of proved plus probable reserves evaluated by the independent engineers at December 31, 2020 including approximately 1,042 gross (983.7 net) future drilling locations recognized in the Consolidated Reserve Report.

Peace River High Triassic Oil Complex

The third core area on the Alberta portion of the greater Peace River High is the Company's exploration and production complex at Spirit River-Mulligan-Earring and Wapiti, Alberta. The majority of the current production in the complex is derived from oil and natural gas-charged reservoirs of the Triassic Charlie Lake and Montney formations as well as the newly added Wapiti Cardium formation. This area, currently producing approximately 23,000 Boe/d net to Tourmaline, has a large inventory of vertical and horizontal development drilling prospects in the Charlie Lake, Montney, and Wapiti Cardium formations as well as attractive plays in several other formations. The Company has drilled 355 horizontal oil wells to date and plans an additional approximately 10 gross horizontals through 2021. As at December 31, 2020, the Company has a defined inventory of 1,179 future Charlie Lake horizontal locations (gross), 252 Wapiti Cardium horizontals (gross), and 631 Montney horizontals (gross).

Proved plus probable reserves in the area at December 31, 2020 are estimated to be 261.9 MMboe including approximately 589 gross (571.7 net) future drilling locations recognized in the Consolidated Reserve Report. The Company currently owns and operates two significant oil batteries capable of handling 50,000 bpd of fluids and the associated natural gas is delivered to a third party for processing. Tourmaline also has an owned and operated 60 MMcf/d sour gas processing facility at Spirit River.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The statement of reserves data and other oil and gas information set forth below is dated March 1, 2021 and effective as at December 31, 2020.

Disclosure of Reserves Data

The reserves data set forth below is based upon the report of GLJ Ltd. ("**GLJ**") dated effective December 31, 2020, with an execution date of February 19, 2021 (the "**GLJ Reserve Report**") and the report of Deloitte LLP ("**Deloitte**") dated effective December 31, 2020, with an execution date of February 11, 2021 (the "**Deloitte Reserve Report**"), which are contained in the consolidated report of GLJ dated effective December 31, 2020, with a preparation date of March 1, 2021 (the "**Consolidated Reserve Report**"). The Consolidated Reserve Report evaluates, as at December 31, 2020, the crude oil, NGL and natural gas reserves of Tourmaline and, notwithstanding that Tourmaline owns 51.7% of Topaz, includes the full impact of the sale of all assets sold from Tourmaline to Topaz.

Tourmaline's Reserves and Net Present Values of Future Net Revenue included in the Statement of Reserves Data and Other Oil and Gas Information contained herein include the full impact of the sale of all assets and revenue streams sold by Tourmaline to Topaz notwithstanding Tourmaline's 51.7% ownership interest in Topaz. The Net Present Values of Future Net Revenue on a Total Proved Plus Probable basis (discounted at a rate of 10%) would increase by approximately 6.5% had the Topaz transaction not occurred. On a Proved Producing and Total Proved basis, the Net Present Values of Future Net Revenue (discounted at a rate of 10%) would increase by approximately 8.5% and 7.6%, respectively.

GLJ evaluated in the GLJ Reserve Report approximately 84.2% of the assigned total proved plus probable reserves and 85.8% of the total proved plus probable future net revenue discounted at 10% recognized in the Consolidated Reserve Report. Deloitte evaluated in the Deloitte Reserve Report approximately 15.8% of the assigned total proved plus probable reserves and 14.2% of the total proved plus probable future net revenue discounted at 10% recognized in the Consolidated Reserve Report. Deloitte evaluated in the Deloitte Reserve Report the Company's greater Hinton, Kakwa, Alberta Foothills and Wolf Creek (Modern) properties located in the Alberta Deep Basin and the Company's Mulligan, Spirit River, and Wapiti properties located in the Alberta portion of the Peace River High. Deloitte incorporated the forecast price and cost assumptions as described below under the heading "Consolidated Reserve Report Pricing Assumptions" in their evaluation. GLJ evaluated in the GLJ Reserve Report the balance of the Company's properties.

GLJ prepared the Consolidated Reserve Report by consolidating the GLJ Reserve Report with the Deloitte Reserve Report adjusted to apply certain of GLJ's assumptions and methodologies used in the preparation of the GLJ Reserve Report to the Deloitte Reserve Report. Accordingly, the consolidated reserves information below varies from the reserve information that would be derived from a simple arithmetic summation of the GLJ Reserve Report and the Deloitte Reserve Report. Also due to rounding, certain columns may not add. The price forecast used in the reserve evaluations is an equal weighted average of the January 1, 2021 price forecasts for GLJ, Sproule Associates Ltd. and McDaniel & Associates Consultants Ltd.

The Consolidated Reserve Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Tourmaline believes is important to readers of this Annual Information Form. GLJ and Deloitte were engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

Shale natural gas is required to be presented separately from conventional natural gas as its own product type pursuant to NI 51-101. While the Tourmaline Montney reserves do not strictly fit the definition of "shale gas" as defined in NI 51-101 because the natural gas is not "primarily adsorbed" as stated within the definition, the Montney reserves have been included as shale gas for purposes of this disclosure.

All of the Company's consolidated reserves are in Canada and, more specifically, substantially all are in the provinces of Alberta and British Columbia.

The applicable Reports on Reserves Data by Independent Qualified Reserves Evaluators in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Schedules A through B to this Annual Information Form.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. In general, 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 and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers

at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

The information relating to the Company's crude oil, NGL and natural gas reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment and reclamation costs. See "Forward-Looking Statements", "Certain Reserves Data Information", "Industry Conditions" and "Risk Factors – Reserves Estimates".

Reserves and Future Net Revenue Data (Forecast Prices and Costs)

The following tables summarize the Company's gross reserves defined as the working interest share of reserves prior to the deduction of interest owned by others (burdens). Royalty interest reserves are not included in Company gross reserves. Company net reserves are defined as the working net carried, and royalty interest reserves after deduction of all applicable burdens.

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue as of December 31, 2020 Forecast Prices and Costs⁽¹⁾

Reserves Category	Light & Medium Crude Oil		Conventional Natural Gas		Shale Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
	Company Gross (Mbbbls)	Company Net (Mbbbls)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (Mbbbls)	Company Net (Mbbbls)	Company Gross (Mboe)	Company Net (Mboe)
Proved Producing	14,638	12,807	2,187,332	1,990,250	1,262,996	1,100,036	146,755	127,125	736,448	654,979
Proved Developed Non-Producing	1,791	1,430	86,881	79,270	174,689	154,455	10,365	9,203	55,750	49,587
Proved Undeveloped	35,721	30,124	2,327,817	2,139,471	1,921,668	1,700,155	154,889	140,095	898,857	810,156
Total Proved	52,150	44,361	4,602,031	4,208,992	3,359,353	2,954,646	312,008	276,422	1,691,056	1,514,723
Total Probable	50,693	42,936	3,181,653	2,914,958	4,316,151	3,689,427	322,881	280,309	1,623,208	1,423,976
Total Proved Plus Probable	102,843	87,296	7,783,684	7,123,950	7,675,505	6,644,073	634,890	556,731	3,314,264	2,938,698

Net Present Values of Future Net Revenue (\$000s)

Reserves Category	Before Income Taxes Discounted at ⁽²⁾ (%/year)						After Income Taxes Discounted at ⁽²⁾⁽³⁾ (%/year)						Unit Value Before Income Tax Discounted at 10%/year	
	0	5	8	10	15	20	0	5	8	10	15	20	(\$/Boe)	(\$/Mcf)
	Proved Producing.....	8,659,201	7,102,128	6,390,964	5,993,613	5,203,745	4,621,172	8,659,201	7,102,128	6,390,964	5,993,613	5,203,745	4,621,172	9.15
Proved Developed Non-Producing	763,691	592,722	523,565	486,385	414,782	363,460	606,060	512,097	468,528	443,379	390,975	349,840	9.81	1.63
Proved Undeveloped.....	8,898,335	5,746,758	4,549,177	3,931,094	2,804,494	2,060,860	6,942,509	4,463,850	3,523,500	3,038,714	2,155,890	1,573,309	4.85	0.81
Total Proved.....	18,321,228	13,441,608	11,463,706	10,411,091	8,423,021	7,045,492	16,207,770	12,078,075	10,382,992	9,475,706	7,750,610	6,544,320	6.87	1.15
Total Probable.....	21,803,472	11,347,402	8,240,697	6,812,064	4,502,129	3,180,028	16,789,742	8,677,720	6,271,191	5,167,025	3,388,007	2,375,947	4.78	0.80
Total Proved Plus Probable.....	40,124,699	24,789,010	19,704,403	17,223,156	12,925,150	10,225,520	32,997,511	20,755,796	16,654,183	14,642,731	11,138,617	8,920,267	5.86	0.98

Notes:

- (1) Numbers may not add due to rounding.
- (2) Values are presented on the basis that all Revenue Streams sold to Topaz are excluded from these tables notwithstanding the fact Tourmaline owns 51.7% of Topaz. Values also exclude other income generated by Topaz.
- (3) The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis. It does not consider the Company's tax situation, or tax planning. It does not provide an estimate of the value at the Company level which may be significantly different. The Company's financial statements and management's discussion and analysis should be consulted for information at the Company level.

Total Future Net Revenue (\$000s)
(Undiscounted)
as of December 31, 2020
Forecast Prices and Costs⁽¹⁾⁽²⁾

Reserves Category	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment and Reclamation Costs ⁽³⁾	Future Net Revenue Before Income Tax	Income Tax	Future Net Revenue After Income Tax ⁽⁴⁾
Proved Producing.....	15,239,772	1,197,826	4,557,871	3,771	821,102	8,659,201	-	8,659,201
Proved Developed Non-Producing	1,194,349	109,414	261,539	41,756	17,948	763,691	157,632	606,060
Proved Undeveloped.....	19,529,608	1,478,749	4,378,741	4,549,430	224,353	8,898,335	1,955,826	6,942,509
Total Proved.....	35,963,729	2,785,989	9,198,151	4,594,957	1,063,404	18,321,228	2,113,458	16,207,770
Total Probable.....	40,565,147	4,222,391	9,997,501	4,192,615	349,169	21,803,472	5,013,730	16,789,742
Total Proved Plus Probable.....	<u>76,528,876</u>	<u>7,008,379</u>	<u>19,195,653</u>	<u>8,787,572</u>	<u>1,412,573</u>	<u>40,124,699</u>	<u>7,127,188</u>	<u>32,997,511</u>

Notes:

- (1) Numbers may not add due to rounding.
- (2) Values are presented on the basis that all Revenue Streams sold to Topaz are excluded from these tables notwithstanding the fact Tourmaline owns 51.7% of Topaz. Values also exclude other income generated by Topaz.
- (3) Abandonment and Reclamation Costs includes all active and inactive assets, with or without associated reserves, inclusive of all wells (existing and undrilled), facilities and pipelines.
- (4) The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis. It does not consider the Company's tax situation, or tax planning. It does not provide an estimate of the value at the Company level, which may be significantly different. The Company's financial statements and management's discussion and analysis should be consulted for information at the Company level.

Future Net Revenue
by Production Type
as of December 31, 2020
Forecast Prices and Costs

Reserves Category	Production Type ⁽¹⁾	Future Net Revenue Before Income Taxes (discounted at 10%/year) (\$000s) ⁽²⁾	Unit Value (discounted at 10%/year) ⁽²⁾ (\$/Boe)	(\$/Mcf)
Proved Reserves	Light and Medium Crude Oil	978,579	7.94	1.32
	Conventional Natural Gas	4,536,325	5.74	0.96
	Shale Natural Gas	4,896,187	8.15	1.36
	Total	10,411,091	6.87	1.15
Proved Plus Probable	Light and Medium Crude Oil	1,532,383	6.32	1.05
	Conventional Natural Gas	6,765,287	5.13	0.86
	Shale Natural Gas	8,925,486	6.48	1.08
	Total	17,223,156	5.86	0.98

Note:

- (1) By-products, including solution gas, NGLs and other associated by-products are included in their main product group (natural gas or oil).
- (2) Values are presented on the basis that all Revenue Streams sold to Topaz are excluded from these tables notwithstanding the fact Tourmaline owns 51.7% of Topaz. Values also exclude other income generated by Topaz.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- Analysis of drilling, geological, geophysical and engineering data;
- The use of established technology; and
- Specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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

- (a) **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.
- (b) **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.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

- (a) **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.
 - (i) **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.
 - (ii) **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.
- (b) **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.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide 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.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above 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 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A quantitative 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.

- (5) Well abandonment, disconnect and surface reclamation costs were estimated and included in the GLJ report for both wells that were assigned reserves and inactive wells that were not assigned reserves. Complete abandonment, disconnect and surface reclamation costs have also been estimated for gathering systems, batteries, plants and processing facilities.

Consolidated Reserve Report Pricing Assumptions

Summary of Pricing and Inflation Rate Assumptions Forecast Prices and Costs ⁽¹⁾

Crude Oil and Natural Gas Liquids Pricing

Year	Inflation ⁽²⁾ %	CAD/USD Exchange Rate \$/US\$/Cdn ⁽³⁾	NYMEX WTI Near Month Futures Contract Crude Oil at Cushing, Oklahoma		Brent Blend Crude Oil FOB North Sea Then Current \$/US\$/Bbl	MSW, Light Crude Oil (40 API, 0.3%S) at Edmonton Then Current \$/Cdn\$/Bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current \$/Cdn\$/Bbl	WCS Crude Oil Stream Quality at Hardisty Then Current \$/Cdn\$/Bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current \$/Cdn\$/Bbl	Light Sour Crude Oil (35 API, 1.2%S) at Cromer Then Current \$/Cdn\$/Bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current \$/Cdn\$/Bbl	Alberta Natural Gas Liquids (Then Current Dollars)				Edmonton C5+ Stream Quality \$/Cdn\$/Bbl
			Constant 2021 \$/US\$/Bbl	Then Current \$/US\$/ Bbl								Spec Ethane \$/Cdn\$/Bbl	Edmonton Propane \$/Cdn\$/Bbl	Edmonton Butane \$/Cdn\$/Bbl		
			2021	0.0								0.7683	47.17	47.17	49.42	
2022	1.3	0.7650	49.51	50.17	52.85	59.89	48.96	48.18	43.20	59.31	57.58	8.65	21.91	32.85	63.19	
2023	2.0	0.7633	51.44	53.17	56.04	63.48	52.92	52.10	46.86	62.72	61.05	8.35	24.57	39.20	67.34	
2024	2.0	0.7633	52.14	54.97	57.87	65.76	54.95	54.10	48.67	64.98	63.25	8.46	25.47	40.65	69.77	
2025	2.0	0.7633	52.14	56.07	59.00	67.13	56.05	55.19	49.65	66.33	64.57	8.63	26.00	41.50	71.18	
2026	2.0	0.7633	52.14	57.19	60.15	68.53	57.16	56.29	50.65	67.71	65.91	8.81	26.54	42.36	72.61	
2027	2.0	0.7633	52.14	58.34	61.33	69.95	58.30	57.42	51.67	69.12	67.28	8.99	27.09	43.24	74.07	
2028	2.0	0.7633	52.14	59.50	62.53	71.40	59.47	58.57	52.71	70.56	68.68	9.17	27.65	44.14	75.56	
2029	2.0	0.7633	52.14	60.69	63.75	72.88	60.66	59.74	53.76	72.02	70.10	9.36	28.23	45.06	77.08	
2030	2.0	0.7633	52.14	61.91	65.03	74.34	61.87	60.93	54.84	73.46	71.51	9.55	28.79	45.96	78.62	
2031	2.0	0.7633	52.14	63.15	66.33	75.83	63.11	62.15	55.94	74.93	72.93	9.74	29.37	46.88	80.19	
2032	2.0	0.7633	52.14	64.41	67.66	77.34	64.37	63.39	57.05	76.43	74.40	9.93	29.96	47.82	81.80	
2033	2.0	0.7633	52.14	65.70	69.01	78.89	65.66	64.66	58.19	77.95	75.89	10.13	30.55	48.78	83.43	
2034	2.0	0.7633	52.14	67.01	70.39	80.47	66.97	65.95	59.36	79.51	77.40	10.33	31.16	49.75	85.10	
2035	2.0	0.7633	52.14	68.35	71.80	82.08	68.31	67.28	60.55	81.10	78.95	10.54	31.79	50.75	86.80	
2036	2.0	0.7633	52.14	+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%/yr	+2.0%/yr	+2.0%/yr	

Natural Gas and Sulphur Pricing

Year	NYMEX Henry Hub Near Month Contract		Midwest Price @ Chicago Then Current \$/US\$/MMBtu	AECO/NIT Spot Then Current \$/Cdn\$/MMBtu	Alberta Plant Gate			Saskatchewan Plant Gate			British Columbia	
	Constant 2021 \$/US\$/MMBtu	Then Current \$/US\$/MMBtu			Spot		SaskEnergy \$/Cdn\$/MMBtu	Spot \$/Cdn\$/MMBtu	Sumas Spot \$/US\$/MMBtu	Westcoast Station 2 \$/Cdn\$/MMBtu	Spot Plant Gate \$/Cdn\$/MMBtu	
	Constant 2021 \$/US\$/MMBtu	Then Current \$/US\$/MMBtu			Dawn Price @ Ontario Then Current \$/US\$/MMBtu	Constant 2021 \$/Cdn\$/MMBtu						Then Current \$/Cdn\$/MMBtu
2021	2.83	2.83	2.69	2.78	2.73	2.55	2.56	2.66	2.60	2.76	2.71	2.48
2022	2.83	2.87	2.73	2.70	2.80	2.44	2.47	2.49	2.52	2.75	2.62	2.38
2023	2.81	2.90	2.76	2.61	2.83	2.31	2.38	2.40	2.50	2.43	2.53	2.30
2024	2.81	2.96	2.82	2.65	2.89	2.30	2.42	2.43	2.53	2.47	2.82	2.33
2025	2.81	3.02	2.88	2.70	2.94	2.30	2.47	2.48	2.58	2.52	2.88	2.38
2026	2.80	3.08	2.94	2.76	3.00	2.30	2.52	2.53	2.64	2.58	2.94	2.43
2027	2.81	3.14	3.00	2.81	3.06	2.30	2.57	2.59	2.69	2.63	3.00	2.48
2028	2.80	3.20	3.06	2.86	3.12	2.30	2.62	2.64	2.75	2.68	3.06	2.53
2029	2.80	3.26	3.12	2.92	3.18	2.30	2.68	2.70	2.80	2.74	3.12	2.59
2030	2.80	3.33	3.18	2.98	3.25	2.30	2.74	2.75	2.86	2.80	3.18	2.64
2031	2.80	3.39	3.25	3.04	3.32	2.30	2.79	2.81	2.91	2.86	3.24	2.69
2032	2.80	3.46	3.32	3.10	3.38	2.30	2.85	2.86	2.97	2.92	3.31	2.74
2033	2.80	3.53	3.38	3.16	3.45	2.30	2.90	2.92	3.03	2.98	3.38	3.06
2034	2.80	3.60	3.45	3.23	3.52	2.31	2.96	2.98	3.10	3.04	3.45	3.12
2035	2.80	3.67	3.52	3.29	3.59	2.30	3.02	3.04	3.16	3.10	3.52	3.18
2036	2.80	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.30	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Notes:

- (1) Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Reserve Report and Deloitte in the Deloitte Reserve Report, were an average of forecast prices and costs published by Sproule Associates Ltd. as at December 31, 2020 and GLJ and McDaniel & Associates Consultants Ltd. as at January 1, 2021 (each of which is available on their respective websites at www.sproule.com, www.gljpc.com, and www.mcdan.com). GLJ assigns a value to the Company's existing physical diversification contracts for natural gas for consuming markets at Dawn, Chicago, Ventura, Malin, PG&E, Iroquois, and Kingsgate based on forecasted differentials to NYMEX Henry Hub as per the aforementioned consultant average price forecast, contracted volumes and transportation costs. No incremental value is assigned to potential future contracts which were not in place as of December 31, 2020.
- (2) Inflation rates used for forecasting prices and costs.
- (3) Exchange rates used to generate the benchmark reference prices in this table.

During the year ended December 31, 2020, the Company received the following weighted average prices, including realized gains and losses on financial instruments, in respect of its production: natural gas – \$2.68/Mcf; NGL – \$14.80/bbl; and oil and condensate – \$51.73/bbl. The overall weighted average price received by Tourmaline on an oil equivalent basis was \$19.13/Boe.

Additional Information Relating to Reserves Data

The additional information contained in this section pertains to Tourmaline and Exshaw on a consolidated basis and references to Tourmaline include Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw for year 2018 as well as from January 1, 2019 to October 31, 2019). On October 31, 2019, Exshaw became a wholly-owned subsidiary of Tourmaline.

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to Tourmaline's properties as at the end of the financial years ended December 31, 2020, 2019 and 2018.

Proved Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbbl)		Conventional Natural Gas (MMcf)		Shale Natural Gas ⁽²⁾ (MMcf)		Natural Gas Liquids (Mbbbl)		MBoe Oil Equivalent	
	First Attributed ⁽¹⁾	Cumulative at Year-end	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	4,056	25,008	266,730	1,927,661	178,286	1,310,007	16,658	106,988	94,884	671,607
2019	2,370	32,189	128,803	1,929,133	130,035	1,408,310	11,108	113,735	56,618	702,164
2020	6,052	35,721	667,490	2,327,817	538,034	1,921,668	47,581	154,889	254,553	898,857

Notes:

- (1) "First Attributed" refers to reserves first attributed on the effective date of the corresponding fiscal year.
- (2) Because of product type guidelines and definitions, contained in NI 51-101, the Company's Montney proved reserves are classified as shale natural gas.

It is anticipated that most of the proved undeveloped locations will be drilled by December 31, 2025.

Probable Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbbl)		Conventional Natural Gas (MMcf)		Shale Natural Gas ⁽²⁾ (MMcf)		Natural Gas Liquids (Mbbbl)		MBoe Oil Equivalent	
	First Attributed ⁽¹⁾	Cumulative at Year-end	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	4,699	35,637	268,608	1,793,200	84,574	3,085,264	14,790	209,952	78,353	1,058,666
2019	4,961	42,224	140,471	1,821,303	224,623	3,249,233	16,397	215,010	82,206	1,102,323
2020	2,265	43,450	684,588	2,462,221	757,792	3,840,795	62,900	271,964	305,562	1,365,917

Notes:

- (1) "First Attributed" refers to reserves first attributed on the effective date of the corresponding fiscal year.
- (2) Because of product type guidelines and definitions, contained in NI 51-101, the Company's Montney probable reserves are classified as shale natural gas.

It is anticipated that most of the future development capital associated with the probable undeveloped reserves will be incurred by December 31, 2027.

In general, once proved and/or probable undeveloped reserves are identified, they are scheduled into Tourmaline's development plans. Normally, Tourmaline plans to develop its proved and probable undeveloped reserves within three to seven years. A number of factors that could result in delayed or cancelled development are as follows: changing economic conditions (due to pricing, operating and capital expenditure fluctuations); changing technical conditions (production anomalies such as water breakthrough or accelerated depletion); multi-zone developments (delay of a prospective formation completion until the initial completion is no longer economic); a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and surface access issues (landowners, weather conditions and/or regulatory approvals). See "Risk Factors" and "Industry Conditions".

Significant Factors or Uncertainties Affecting Reserves Data

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

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

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

Other than as discussed above and the various risks and uncertainties that participants in the oil and natural gas industry are exposed to generally, Tourmaline is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed in this Annual Information Form. See "*Risk Factors*" and "*Industry Conditions*".

GLJ's forecast of well abandonment and reclamation costs for all wells with reserves assigned are included in their report and therefore in their estimate of future net revenue. Abandonment and reclamation costs for wells for which no reserves are assigned and for Company-owned facilities are also included for the purposes of calculating GLJ's estimate of future net revenue. Refer to note 8 "*Decommissioning Obligations*" in the Financial Statements for further discussion on the Company's abandonment and reclamation obligations, which note is incorporated by reference herein.

The following table sets forth abandonment and reclamation costs deducted in the estimation of future net revenue in the Consolidated Reserve Report:

<u>Year</u>	<u>Forecast Prices and Costs (Total Proved plus Probable) (\$000s)</u>	
	<u>Abandonment and Reclamation Costs (Undiscounted)</u>	<u>Abandonment and Reclamation Costs (Discounted at 10%)</u>
2021	3,173	3,025
2022	3,187	2,762
2023	3,410	2,687
Thereafter	1,402,803	143,957
Total	1,412,573	152,431

Future Development Costs

The following table sets forth development costs deducted in the estimation of Tourmaline's future net revenue attributable to the reserve categories noted below (\$000s):

Year	Undiscounted Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves
	2021	948,529
2022	948,745	1,341,747
2023	1,093,323	1,361,171
2024	868,217	1,301,324
2025	510,647	1,230,567
Thereafter	225,496	2,269,721
Total	4,594,957	8,787,572

Tourmaline expects that the capital listed in the preceding table will be funded through its existing cash balance, unutilized credit facilities, expected cash flow from operations and completed financings.

Other Oil and Natural Gas Information

Crude Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which Tourmaline had a working interest as at December 31, 2020 and that Tourmaline considers capable of production.

	Crude Oil Wells⁽¹⁾				Natural Gas Wells⁽¹⁾			
	Producing		Non-Producing⁽²⁾		Producing		Non-Producing⁽²⁾	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta ⁽¹⁾	417	385.6	142	119.5	2,497	2,123.9	437	326.0
British Columbia ⁽¹⁾	2	0.3	16	4.2	777	705.2	341	286.0
Saskatchewan ⁽¹⁾	1	0.1	-	-	-	-	-	-
Total	420	386.0	158	123.7	3,274	2,829.1	778	612.0

Notes:

- (1) All of Tourmaline's wells are located onshore.
- (2) The non-producing oil wells and natural gas wells capable of production but which are not currently producing will be re-evaluated with respect to future product prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

For a general description of Tourmaline's important properties, facilities and installations, see "*Description of Core Long-Term Growth Areas*".

Landholdings

The following table sets out Tourmaline's developed and undeveloped properties as at December 31, 2020, in which Tourmaline has an interest. When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. When there are multiple discontinuous rights in a single lease, the acreage is reported only once.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	1,211,491	958,428	1,647,380	1,409,730	2,858,871	2,368,158
British Columbia	314,566	243,020	382,438	322,676	697,004	565,696
Saskatchewan	688	219	69,722	65,930	70,410	66,149
Total	1,526,745	1,201,667	2,099,540	1,798,336	3,626,285	3,000,003

Notes:

(1) Numbers may not add due to rounding.

Properties with no Attributable Reserves

The following table sets forth the gross and net acres of unproved properties held by Tourmaline as at December 31, 2020.

Unproved Properties as at December 31, 2020		
	Gross Acres	Net Acres
Alberta	1,074,458	917,413
British Columbia	11,141	9,400
Saskatchewan	69,722	65,930
Total	1,155,321	992,743

The maximum net area for which the Company expects the rights to explore, develop and exploit to expire during 2021 is 422,199 acres in Alberta, 25,063 acres in British Columbia and 61 acres in Saskatchewan. Included in these amounts are 2020 expiries that were extended to 2021 by provincial regulatory bodies as a result of COVID relief and other programs. The expiring acreage is continuously being evaluated and attempts will be made to maintain the Company's rights on the acreage and mitigate expiries through land swaps, asset dispositions or drilling to maintain the lease. There are no material work commitments necessary to maintain these properties.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

For information with respect to the Company's reclamation and abandonment obligations for the properties to which reserves have been attributed, see "Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data" in this Annual Information Form.

Tax Horizon

Tourmaline has no current tax expense and, based on Company estimates, will be able to realize the benefit of its non-capital losses and, at a minimum, expects to remain non-taxable throughout the Company's current 5 year plan. Tourmaline has approximately \$9.8 billion of tax pools available as at December 31, 2020, which can be used to offset taxable income in future years. The Company also has \$8.9 million of scientific research and development investment tax credits to apply against future taxes payable.

Capital Expenditures

The following table summarizes capital expenditures (including property acquisitions, net of dispositions, as well as capitalized general administrative expenses) related to Tourmaline's activities for the year ended December 31, 2020:

	\$000s
Exploration, drilling and completions	678,480
Development, equipping and tie-in	130,411
Property acquisitions ⁽¹⁾	171,871
Property dispositions.....	(235)
Facilities	64,206
Geological and geophysical.....	5,670
Other (including capitalized G&A)	33,222
Total⁽²⁾	1,083,625
Less: Topaz property acquisitions ⁽³⁾	(119,000)
Adjusted Total⁽²⁾	964,625

Notes:

- (1) Property acquisitions are a result of approximately \$8.1 million of acquired proved properties and approximately \$44.8 million of acquired unproved properties.
- (2) Includes other capital expenditures incurred by Topaz (without reduction to reflect the 48.3% non-controlling interest in Topaz).
- (3) Includes property acquisitions incurred by Topaz from non-related parties.

Exploration and Development Activities

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

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Natural Gas	1	1	175	166.6
Oil	-	-	14	13.3
Service	-	-	-	-
Dry	-	-	-	-
Total	1	1	189	179.9

See "*Description of Core Long-Term Growth Areas*" and "*Description of the Business*" for a description of Tourmaline's exploration and development plans.

Production Estimates

The following table sets out the volume of Tourmaline's production estimated for the year ended December 31, 2021 as evaluated by GLJ and Deloitte, which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data" above.

	Light and Medium Crude Oil	Conventional Natural Gas	Shale Natural Gas	Natural Gas Liquids	Oil Equivalent Total
	Company Gross (Bbls/d)	Company Gross (Mcf/d)	Company Gross (Mcf/d)	Company Gross (Bbls/d)	Company Gross (Boe/d)
Proved Producing	8,517	1,017,711	553,486	68,396	338,779
Proved Developed Non- Producing.....	314	49,701	76,125	5,406	26,691
Proved Undeveloped	1,683	235,232	170,461	16,491	85,790
Total Proved	10,514	1,302,645	800,072	90,293	451,260
Total Probable	185	123,482	131,696	12,685	55,400
Total Proved Plus Probable	<u>10,699</u>	<u>1,426,127</u>	<u>931,768</u>	<u>102,979</u>	<u>506,660</u>

Notes:

- (1) No one field accounted for 20% or more of Tourmaline's estimated 2021 total proved production in the Consolidated Reserve Report.
- (2) Numbers may not add due to rounding.

Production History

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

	Quarter Ended			
	2020⁽¹⁾⁽²⁾⁽³⁾			
	March 31	June 30	September 30	December 31
Average Daily Production ⁽⁴⁾				
Light and Medium Crude Oil (Bbl/d)	27,870	27,972	27,248	29,113
Conventional Natural Gas (Mcf/d)	960,191	889,490	864,599	993,899
Shale Natural Gas (Mcf/d)	514,490	535,709	549,384	598,111
NGL (Bbl/d)	34,699	33,864	35,290	41,877
Combined (Boe/d)	308,349	299,369	298,202	336,325
Average Price Received				
Light and Medium Crude Oil (\$/Bbl)	63.12	37.67	51.42	54.50
Conventional Natural Gas (\$/Mcf)	2.67	2.65	2.81	3.38
Shale Natural Gas (\$/Mcf)	2.05	2.01	2.27	2.87
NGL (\$/Bbl)	11.40	11.32	15.82	19.53
Combined (\$/Boe)	18.71	16.28	18.89	22.25
Royalties Paid.....				
Light and Medium Crude Oil (\$/Bbl)	4.77	2.09	2.34	4.18
Conventional Natural Gas (\$/Mcf) ⁽⁵⁾	(0.05)	(0.02)	(0.07)	-
Shale Natural Gas (\$/Mcf)	0.11	0.10	0.10	0.23
NGL (\$/Bbl)	1.31	1.01	0.99	1.24
Combined (\$/Boe)	0.60	0.42	0.31	0.93
Production Costs (includes transportation).....				
Light and Medium Crude Oil (\$/Bbl)	12.20	12.45	12.63	12.77
Conventional Natural Gas (\$/Mcf)	1.44	1.47	1.42	1.45
Shale Natural Gas (\$/Mcf)	1.04	1.20	1.33	1.28
NGL (\$/Bbl) ⁽⁶⁾	-	-	-	-
Combined (\$/Boe)	7.32	7.66	7.82	7.67
Netback Received (\$/Boe) ⁽⁷⁾	10.79	8.20	10.76	13.65

Notes:

- (1) Includes Topaz (without reduction to reflect the 48.3% non-controlling interest in Topaz).
- (2) Numbers may not add due to rounding.

- (3) For the purposes of this disclosure, condensate has been combined with Light and Medium Crude Oil as the associated revenues and certain costs of condensate are similar to Light and Medium Crude Oil. Accordingly, NGLs in this disclosure exclude condensate.
- (4) Before deduction of royalties.
- (5) Includes royalty reductions for the quarters ended March 31, June 30, September 30 and December 31 of \$0.13/Mcf, \$0.09/Mcf, \$0.14Mcf and \$0.10/Mcf, respectively, relating to the entire Alberta Gas Cost Allowance credits received by the Company.
- (6) NGL volumes are derived from natural gas production, as such all the related operating costs are attributed to the production of natural gas.
- (7) Netbacks are calculated by subtracting royalties and production costs from revenues.

The following table sets forth the average daily production volumes for the year ended December 31, 2020 for each of the important fields, aggregated by area, comprising Tourmaline's assets.

Area	Light Crude Oil and Medium Crude Oil (bbl/d)	NGLs (bbl/d)	Conventional Natural Gas (Mcf/d)	Shale Natural Gas (Mcf/d)	Total (boe/d)
Alberta Deep Basin	6,501	20,201	866,034	-	171,041
Other Alberta properties	8,702	1,635	61,206	-	20,538
British Columbia properties.....	12,848	14,609	-	549,373	119,019
Total⁽¹⁾	28,051	36,445	927,240	549,373	310,598

Note:

- (1) For the purposes of this disclosure, condensate has been combined with Light and Medium Crude Oil as the associated revenues and certain costs of condensate are similar to Light and Medium Crude Oil. Accordingly, NGLs in this disclosure exclude condensate

The Company's production for the year ended December 31, 2020 was 9.0% light and medium crude oil (including condensate), 11.7% NGLs, 49.7% conventional natural gas and 29.5% shale natural gas.

For the year ended December 31, 2020, approximately 33.5% of the Company's revenue, which is defined as the sum of commodity sales from production, premium (loss) on risk management activities and realized gains on financial instruments, was derived from crude oil production (including NGLs), 45.1% was derived from conventional natural gas production and 21.4% was derived from shale natural gas production.

Forward Contracts and Marketing

The Company's commodity hedging policy has been established with the Board authorizing management to hedge up to 50% of current production. Other than as disclosed in the Financial Statements, Tourmaline is not bound by any agreement (including any transportation agreement), directly or through an aggregator, under which it is precluded from fully realizing, or may be protected from the full effect of, future market prices for crude oil or natural gas. Refer to note 4(c) "*Financial Risk Management – Market Risk*" in the recently filed Consolidated Financial Statements of the Company as at and for the years ended December 31, 2020 and 2019 for further discussion on the Company's commodity hedging activities.

Tourmaline's transportation obligations or commitments for future physical deliveries of crude oil and natural gas are not expected to vary significantly from Tourmaline's future forecasted production.

OTHER BUSINESS INFORMATION

Specialized Skill and Knowledge

Tourmaline employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills, which are widely available in the industry. Drawing on significant experience in the oil and gas business, Tourmaline believes its management team has a demonstrated track record of bringing together all of the key

components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Tourmaline to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

The oil and natural gas industry is very competitive. As the largest natural gas producer in Canada, Tourmaline, which currently produces between 1.8 and 1.9 Bcf/d, controls an estimated 11% percent of Western Canada's dry natural gas production and has a strong competitive position in its core areas (see "*Description of Core Long-Term Growth Areas*").

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 Tourmaline competes with a substantial number of other entities, some of which have greater technical or financial resources. With the maturing nature of the WCSB, the access to new prospects is becoming more competitive and complex.

Tourmaline 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 Tourmaline 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 generally cyclical. 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 and Extreme Weather Conditions*".

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 Tourmaline see "*Industry Conditions – Environmental Regulation*" and "*Risk Factors – Environmental*".

On November 8, 2017, the Board established a new Committee comprised of independent directors: the Environment, Sustainability and Safety Committee. The purpose of this Committee is to oversee policies relating to environment, health, safety and sustainability matters. Tourmaline leverages technology and innovative strategies to minimize its environmental impact, and in this regard, the Company has developed robust and integrated air emissions, water and land use strategies designed to reduce the impact of its operations on the environment. The Company's most recent Sustainability Report can be found on the Company's website at www.tourmalineoil.com.

Employees

At December 31, 2020, Tourmaline had 225 full time employees and 41 consultants located at its Calgary office, and 71 full time employees and 267 contract operators in various field locations. Tourmaline currently has

224 full time employees and 39 consultants located at its Calgary office, and 72 full time employees and 262 contract operators in various field locations.

Reorganizations

Other than disclosed under "*General Development of the Business*", Tourmaline has not completed any material reorganization within the three most recently completed financial years or during the current financial year. No material reorganization is planned for the current financial year. See "*General Development of the Business*".

Environmental, Health and Safety Policies

Tourmaline supports environmental protection and employee health and safety by integrating the essential principles and practices through its environmental management systems and employee occupational health and safety programs. Tourmaline promotes safety and environmental awareness and protection through the implementation and communication of Tourmaline's environmental management and employee occupational health and safety programs, policies and procedures. Committee structures are established in Tourmaline's operations which are designed to allow for employee participation and development of policies and programs which provide employees with job orientation, training, instruction and supervision to assist them in conducting their activities in an environmentally responsible and safe manner.

Tourmaline 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. Tourmaline conducts audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist in achieving the objectives of the described policies and programs.

Tourmaline also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. Tourmaline's environmental and occupational health and safety management systems are designed to manage such risks in Tourmaline's business and allow action to be taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety audits.

DIVIDENDS

On March 6, 2018, the Board declared its first quarterly dividend of \$0.08 per Common Share payable on March 29, 2018 to shareholders of record on March 14, 2018. Prior to such time, Tourmaline has never declared or paid any cash dividends on the Common Shares. Subsequent to its first quarterly dividend payment, Tourmaline increased its quarterly dividend by 25% to \$0.10 per Common Share for the last two dividend payments of 2018 and further increased its quarterly dividend by 20% to \$0.12 per Common Share for the last three dividend payments of 2019. Tourmaline elected to further increase its quarterly dividend by 17% to \$0.14 per Common Share for the last dividend payment of 2020. Subsequent to December 31, 2020, Tourmaline announced an additional 14% increase to its dividend to \$0.16 per Common Share.

Dividend History

Date Paid	Amount per Common Share
March 29, 2018	\$0.08
June 29, 2018	\$0.09
September 28, 2018	\$0.10
December 28, 2018	\$0.10
March 29, 2019	\$0.10

Dividend History

Date Paid	Amount per Common Share
June 28, 2019	\$0.12
September 30, 2019	\$0.12
December 31, 2019	\$0.12
March 31, 2020	\$0.12
June 30, 2020	\$0.12
September 30, 2020	\$0.12
December 31, 2020	\$0.14

Tourmaline's intention will be to pay quarterly cash dividends on the Common Shares from its free cash flow (cash flow less total capital expenditures, including exploration and production capital and other corporate expenditures and excluding acquisition and core disposition activities, and is prior to dividend payments) to shareholders of record as of the dividend record date which is usually approximately 15 days prior to the dividend payment date. Tourmaline's dividend policy is intended to provide shareholders with relatively stable and predictable quarterly dividends, while retaining a portion of free cash flow to provide the Company with the financial flexibility to either reduce corporate debt, modify the development plan or pursue strategic acquisitions, as deemed appropriate.

In determining the level of dividends to be declared, the Board takes into consideration such factors as current and expected future levels of free cash flow (including income tax), capital expenditures, borrowings and debt repayments, changes in working capital requirements and other factors.

Over the long term, Tourmaline expects to continue to pay dividends from its free cash flow; however, credit facilities may be used to stabilize dividends from time to time. Growth capital expenditures will be funded from retained cash flow from operating activities, proceeds from asset dispositions and proceeds from additional debt or equity, as required. Although Tourmaline intends to continue to make regular quarterly dividends to shareholders, dividends are not guaranteed.

Notwithstanding the foregoing, the amount of future cash dividends declared and paid by Tourmaline, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, compliance with any restrictions on the declaration and payment of dividends contained in any agreements to which Tourmaline is a party from time to time (including, without limitation, the agreements governing Tourmaline's credit facilities), and the satisfaction of liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends.

The Board intends to review this policy on a quarterly basis. Depending on the foregoing factors and any other factors that the Board deems relevant from time to time, many of which are beyond the control of the Board and Tourmaline's management team, the Board may change this policy following any such quarterly review or at any other time that the Board deems appropriate. Any such change may result in future cash dividends being reduced or suspended entirely.

The Board intends that dividends declared and paid by Tourmaline will qualify as "eligible dividends" for the purposes of the *Income Tax Act* (Canada) (and any similar applicable provincial legislation), and thus qualify for the enhanced gross-up and tax credit regime available to certain shareholders. The Board therefore intends to designate dividends paid by Tourmaline as "eligible dividends" and notify shareholders that dividends are "eligible dividends" for these purposes by posting a general notice to this effect on Tourmaline's website and by disclosing this fact in each press release that Tourmaline issues that contains a dividend announcement. Notwithstanding the foregoing, no assurances can be given that all dividends will qualify as "eligible dividends" and the designation of dividends as "eligible dividends" will be subject to the discretion of the Board.

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

The authorized share capital of Tourmaline consists of an unlimited number of Common Shares and an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

The following is a summary of the rights, privileges, restrictions and conditions attaching to the shares in Tourmaline's share capital.

Common Shares

Tourmaline is authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Tourmaline. Subject to the rights of the holders of First Preferred Shares and Second Preferred Shares and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by the Board and upon liquidation, dissolution or winding-up to receive the remaining property of Tourmaline.

First Preferred Shares

The First Preferred Shares are issuable in series and will have such rights, restrictions, conditions and limitations as the Board may from time to time determine. No First Preferred Shares have been issued.

Tourmaline is authorized to issue an unlimited number of First Preferred Shares without nominal or par value. Holders of First Preferred Shares are entitled to receive dividends if, as and when declared by the Board, in priority to holders of Common Shares and Second Preferred Shares. In the event of a liquidation, dissolution or winding-up of Tourmaline, holders of the First Preferred Shares are entitled to receive a rateable share of all distributions made in priority to the holders of the Common Shares and Second Preferred Shares.

Second Preferred Shares

The Second Preferred Shares are issuable in series and will have such rights, restrictions, conditions and limitations as the Board may from time to time determine. No Second Preferred Shares have been issued.

Tourmaline is authorized to issue an unlimited number of Second Preferred Shares without nominal or par value. Holders of Second Preferred Shares are entitled to receive dividends if, as and when declared by the Board subject to the preference of First Preferred Shares but in priority to holders of Common Shares. In the event of a liquidation, dissolution or winding-up of Tourmaline, holders of the Second Preferred Shares are entitled to receive a rateable share of all distributions made, subject to the preference of holders of First Preferred Shares but in priority to holders of Common Shares.

Constraints

There are currently no constraints imposed on the ownership of securities of the Company to ensure that Tourmaline has a required level of Canadian ownership.

Ratings

The following information with respect to the Corporation's credit ratings is provided as it relates to Tourmaline's financing costs and liquidity. Specifically, credit ratings may affect Tourmaline's ability to obtain short-term and long-term financing and impact the cost of such financing. A reduction in the current ratings on the Corporation's debt by its rating agencies, particularly a downgrade below investment grade ratings, could adversely affect Tourmaline's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect Tourmaline's ability to enter into, and the associated costs of entering into, normal course derivative or hedging transactions. DBRS is a rating agency that provides credit ratings. Credit ratings are intended

to provide investors with an independent measure of credit quality of any issues of debt securities. The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the securities, nor do the ratings comment on market price or suitability for a particular investor. Any rating may not remain in effect for a given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgement circumstances so warrant. The Corporation has paid DBRS its customary fees in connection with the provision of the below ratings. Other than fees related to the January 25, 2021 issuance of senior unsecured notes by Tourmaline, the Corporation has not made any payments to DBRS over the past two years for services unrelated to the provision of such ratings.

DBRS has ten rating categories for long-term debt and long term-issuer credit ratings, which range from "AAA" to "D". DBRS uses "high" and "low" designations on ratings from AA to C to indicate the relative standing within a particular rating category. The absence of a "high" or "low" designation indicates that a rating is in the middle of the category. On September 9, 2020, DBRS issued the Corporation's public "Issuer Rating" of "BBB" and in January 2021 its Senior Unsecured Notes rating of "BBB". Trends for these ratings are "stable". A BBB rating is the fourth highest rating of DBRS' ten rating categories for long-term debt and issuer rating.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares trade on the Toronto Stock Exchange (the "TSX") under the symbol TOU. The following table sets forth the price ranges and volume traded on the TSX on a monthly basis for each month of the most recently completed financial year:

	Common Shares		
	Price Range		Trading Volume
	High (\$/share)	Low (\$/share)	
2020			
January	\$16.09	\$13.13	29,026,213
February	\$13.77	\$10.72	26,951,542
March	\$11.41	\$6.73	66,690,592
April	\$14.27	\$8.15	46,465,182
May.....	\$14.95	\$12.66	27,378,674
June.....	\$14.83	\$11.40	48,222,195
July	\$14.00	\$11.90	19,883,997
August	\$18.38	\$13.91	29,410,431
September.....	\$17.44	\$15.36	23,832,322
October	\$19.22	\$15.84	30,665,975
November.....	\$19.94	\$16.63	36,663,895
December	\$18.44	\$16.47	33,799,346

Prior Sales

The following table provides details regarding each class of securities of the Company that are outstanding but not listed or quoted on a market place that have been issued by the Company during the most recently completed financial year.

Options Granted During 2020		
Date of Issuance	Number of Options	Exercise Price of Options
February 15, 2020	74,000	\$12.63
March 15, 2020	30,000	\$9.39
April 15, 2020	116,500	\$10.23
May 15, 2020	18,000	\$13.53
June 15, 2020	25,000	\$12.80
July 15, 2020	72,000	\$12.62
August 31, 2020	3,381,400	\$17.57
September 15, 2020	13,000	\$15.79
October 15, 2020	100,000	\$16.54
November 15, 2020	42,500	\$18.19
December 15, 2020	52,500	\$17.12

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the Company's knowledge, as of December 31, 2020, no securities of Tourmaline are held in escrow or subject to a contractual restriction on transfer.

DIRECTORS AND OFFICERS

Name, Occupation and Security Holding

The names, province or state, and country of residence, positions and offices held with the Company, as at the date of this document, and principal occupation of the directors and officers of the Company are set out below and, in the case of directors, the period each has served as a director of the Company.

Name, Province or State and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since
Michael L. Rose Alberta, Canada	Chairman, President and Chief Executive Officer	Chairman, President and Chief Executive Officer of Tourmaline since August 2008. Prior thereto, Chairman, President and Chief Executive Officer of Duvernay, an oil and gas company.	August 6, 2008
Brian G. Robinson Alberta, Canada	Director and Vice President, Finance and Chief Financial Officer	Director and Vice President, Finance and Chief Financial Officer of Tourmaline since August 2008. Prior thereto, Vice President, Finance and Chief Financial Officer of Duvernay.	October 27, 2008
Jill T. Angevine ⁽¹⁾⁽³⁾⁽⁶⁾ Alberta, Canada	Director	Managing Director of Palisade Capital Management Ltd. since December 2018. Prior thereto, Vice President, Portfolio Manager at Matco Financial Inc. Prior thereto, Vice President and Director, Institutional Research at FirstEnergy Capital Corp.	November 4, 2015
William D. Armstrong ⁽⁴⁾⁽⁶⁾ Colorado, United States	Director	President and Chief Executive Officer of Armstrong Oil & Gas Inc., an oil and gas exploration and production company.	October 27, 2008
Lee A. Baker ⁽³⁾⁽⁴⁾⁽⁵⁾⁽⁶⁾ Alberta, Canada	Director	Independent businessman since June 2016. Prior thereto, Mr. Baker was President and Chief Executive Officer of Nordegg Resources Inc., an oil and gas company, since March 2008. Prior to 2008, Mr. Baker was President and Chief Executive Officer of RSX Energy Inc., an oil and gas company.	March 22, 2011
John W. Elick ⁽⁴⁾⁽⁵⁾⁽⁶⁾ Alberta, Canada	Director	Non-Executive Chairman of Cinch from November 2001 to July 12, 2011 and Chief Executive Officer of Cinch from November 2001 to November 2009.	March 19, 2013
Andrew B. MacDonald ⁽¹⁾⁽²⁾⁽³⁾⁽⁶⁾⁽⁷⁾ British Columbia, Canada	Director	Independent businessman since January 2009. Prior thereto, Co-Head of Canadian Equities and Portfolio Manager with Phillips, Hager & North Investment Management, an investment management company.	March 22, 2011
Lucy M. Miller ⁽²⁾⁽³⁾⁽⁵⁾⁽⁶⁾ Alberta, Canada	Director	Independent businesswoman since December 2016. Prior thereto, President and CEO of United Way of Calgary and Area since 2012 and prior thereto, Chief Superintendent of the Calgary Catholic School District.	June 7, 2017
Ron Wigham ⁽¹⁾⁽²⁾⁽⁴⁾⁽⁶⁾ Alberta, Canada	Director	Independent Businessman since January 2014. Prior thereto Vice-Chairman of Peters & Co. Limited from October 2012, and prior thereto Managing Director, Capital Markets, Peters & Co. Limited.	March 7, 2016
Janet Weiss ⁽⁴⁾⁽⁵⁾⁽⁶⁾ Alaska, United States	Director	Former President of BP Exploration (Alaska), Inc. from 2013 to 2020. Prior thereto, employed by BP America, Inc. (or its predecessors) since 1985.	June 3, 2020
Sherra Aspin Alberta, Canada	Vice President, Marketing	Vice President, Marketing of Tourmaline since September 2018. Prior thereto, Manager of Natural Gas Marketing of Tourmaline.	N/A

<u>Name, Province or State and Country of Residence</u>	<u>Position Held</u>	<u>Principal Occupation for the Last Five Years</u>	<u>Director Since</u>
Allan J. Bush Alberta, Canada	Chief Operating Officer	Chief Operating Officer since May 2019. Prior thereto, Vice President, Operations and Chief Operating Officer since April 2014. Prior thereto, Vice President, Production and Completions since March 2013. Prior thereto, Completions and Operations Engineering Manager of Tourmaline and before that Completions and Operations Engineering Manager of Duvernay Oil Corp.	N/A
Colin Frostad Alberta, Canada	Vice President, Exploration	Vice President, Exploration of Tourmaline since November 2019. Prior thereto, Exploration Manager and Senior Geologist at Tourmaline since 2009 and before that Geologist at Duvernay.	N/A
W. Scott Kirker Alberta, Canada	Secretary and General Counsel	Secretary and General Counsel of Tourmaline since August 2008. Prior thereto, Manager Corporate Affairs of Duvernay.	N/A
Earl H. McKinnon Alberta, Canada	Vice President, Operations	Vice President, Operations since May 2019. Prior thereto, Vice President, Drilling and Completions Operations of Tourmaline since May 2015. Prior thereto, Completions Manager of Tourmaline.	N/A
Sarah Tait Alberta, Canada	Controller	Controller of Tourmaline since September 2015. Prior thereto, Manager of Finance of Tourmaline and before that Chief Financial Officer of Cinch.	N/A
Drew E. Tumbach Alberta, Canada	Vice President, Land and Contracts	Vice President, Land and Contracts of Tourmaline since October 2008. Prior thereto, Vice President, Land and Contracts of Duvernay.	N/A

Notes:

- (1) Member of the Audit Committee. Ms. Angevine is the Chair of the Audit Committee.
- (2) Member of the Compensation Committee. Mr. Wigham is the Chair of the Compensation Committee.
- (3) Member of the Corporate Governance and Nominating Committee. Mr. MacDonald is the Chair of the Corporate Governance and Nominating Committee.
- (4) Member of the Reserves Committee. Mr. Baker is the Chair of the Reserves Committee.
- (5) Member of the Environment, Safety and Sustainability Committee. Ms. Miller is the Chair of the Environment, Sustainability and Safety Committee.
- (6) Independent director.
- (7) Lead Director.

All of the Company's directors' terms of office will expire at the earliest of their resignation, the close of the next annual shareholder meeting 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 or her obligations to the Company. The Company's officers are appointed by and serve at the discretion of the Board.

As of the date of this Annual Information Form, the directors and executive officers of Tourmaline, as a group, beneficially owned, or controlled or directed, directly or indirectly, 20.7 million Common Shares or approximately 7.0% 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 Annual Information Form, or was within 10 years before the date of this Annual Information Form, 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

To the knowledge of the Company, other than as discussed below, 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 Annual Information Form, or has been within the 10 years before the date of this Annual Information Form, 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 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Mr. Baker, a director of Tourmaline, served as President and Chief Executive Officer of Nordegg Resources Inc. ("**Nordegg**"), a private company, until June 10, 2016 and Mr. Rose, the President and Chief Executive Officer and a director of Tourmaline, served as a director of Nordegg until June 10, 2016. On June 16, 2016, a secured creditor of Nordegg was granted an order under the *Bankruptcy and Insolvency Act (Canada)* appointing a receiver to take possession and exercise control over all of Nordegg's current and future assets.

Mr. Wigham, a director of Tourmaline, served as director of Zargon Oil & Gas Ltd. ("**Zargon**"), a publicly traded company on the Toronto Stock Exchange, until September 8, 2020. On September 8, 2020, Zargon filed a Notice of Intention to Make a Proposal under the provisions of Part III, Division I of the *Bankruptcy and Insolvency Act (Canada)* and a trustee was appointed to assist Zargon in its restructuring efforts.

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 entities 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.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

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

Regulatory Actions

There are no:

- (a) penalties or sanctions imposed against Tourmaline by a court relating to securities legislation or by a securities regulatory authority during Tourmaline's financial year;
- (b) other penalties or sanctions imposed by a court or regulatory body against Tourmaline that would likely be considered important to a reasonable investor in making an investment decision; or
- (c) settlement agreements Tourmaline entered into before a court relating to securities legislation or with a securities regulatory authority during Tourmaline's financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any: (a) director or executive officer of Tourmaline; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of Tourmaline'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 the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect Tourmaline.

AUDITOR, TRANSFER AGENT AND REGISTRAR

The Company's auditors are KPMG LLP, Chartered Professional Accountants, Suite 3100, 205 – 5th Avenue S.W., Calgary, Alberta T2P 4B9.

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Company has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made by the Company under National Instrument 51-102 during, or relating to the Company's most recently completed financial year and whose profession or business gives authority to such report, valuation, statement or opinion, are:

- KPMG LLP, Tourmaline's independent auditors; and
- GLJ and Deloitte, Tourmaline's independent reserve evaluators (collectively, the "**Reserve Evaluators**").

Interests of Experts

To the Company's knowledge, no registered or beneficial interests, direct or indirect, in any securities or other property of the Company or of one of the Company's associates or affiliates (i) were held by any of the Reserve Evaluators or by the "designated professionals" (as defined in Form 51-102F2) of the Reserve Evaluators, when the Reserve Evaluators prepared their respective reports, valuations, statements or opinions referred to herein as having been prepared by such Reserve Evaluators, (ii) were received by any of the Reserve Evaluators or the designated professionals of the Reserve Evaluators after such Reserve Evaluator prepared the report, valuation, statement or opinion in question, or (iii) is to be received by any of the Reserve Evaluators or the designated professionals of the Reserve Evaluators.

None of the Reserve Evaluators nor any director, officer or employee of any of the Reserve Evaluators is or is expected to be elected, appointed or employed as a director, officer or employee of the Company or of any associate or affiliate of the Company.

KPMG LLP has advised the Company that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

INDUSTRY CONDITIONS

Companies operating in the oil and gas industry are subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government; and with respect to the pricing and taxation of petroleum and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Western Canadian oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted.

The Corporation's assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of the Corporation's upstream oil and natural gas business include all manner of activities associated with the exploration for and production of 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, including by reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct 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.

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 provinces of Alberta and British Columbia, 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 in Canada

Crude Oil

Oil producers are entitled to negotiate sales contracts directly with purchasers. As a result, macroeconomic and microeconomic market forces determine the price of oil. Worldwide supply and demand factors are the primary

determinant of oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on oil quality, prices of competing products, 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 Organization of the Petroleum Exporting Countries 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

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms of sale.

NGLs

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

The Canada Energy Regulator (the "CER") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and longer-term licences pursuant to its authority under the *Canadian Energy Regulator Act* (the "CERA"). 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.

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 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

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

Under the Canadian Constitution, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines require a federal regulatory review and Cabinet approval before they can proceed. However,

recent years have seen a perceived lack of policy and regulatory certainty in this regard such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments and legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines also require approvals from several levels of government in the United States.

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 United 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 shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards.

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 Order MO 20-10 will remain in place until permanent rule changes are approved.

Natural Gas and Liquefied Natural Gas ("LNG")

Natural gas prices in Western Canada have been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access more markets

and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed relative to other markets.

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 exacerbated by storage limitations. 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 argument took place in late January 2021.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada export terminal announced a positive final investment decision. Once complete, the project will allow producers in NEBC to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Pre-construction activities on the LNG Canada facility began in November 2018, with a 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 addition to LNG Canada and the CGL Pipeline projects, the following is an update on various other LNG Projects that have been proposed in Canada:

- 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. However, both partners are looking to sell some or all of their interest in the project.
- Woodfibre LNG Limited, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. has proposed to build the Woodfibre LNG Project, a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Commission approved a project permit for the Woodfibre LNG Project in July 2019 and a formal approval of the project is expected in the third quarter of 2021, with construction beginning shortly thereafter.
- GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently working its way through a federal impact assessment process for the construction and operation of an LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project is currently slated for completion in 2026.
- Pieridae Energy Ltd.'s ("Pieridae") proposed Goldboro LNG project, located in Nova Scotia, 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, but Pieridae has delayed its final investment decision until mid-2021.
- Finally, Cedar LNG Export Development Ltd.'s Cedar LNG Project near Kitimat, British Columbia, is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office (the "BC EAO") 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 oil pipeline system. A common carrier pipeline must accept all products offered to it for transportation. If there is insufficient capacity to transport the volumes offered, the available capacity is pro-rated to accommodate all shippers. The changes that Enbridge intends to implement include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein shippers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. If the service change is approved, 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.

Curtailement

In December 2018, the Government of Alberta announced that it would mandate a short-term and temporary curtailment of provincial oil and bitumen production. Curtailement first took effect on January 1, 2019. As contemplated in the *Curtailement 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 *Curtailement 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.

International Trade Agreements

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.

Land Tenure

Mineral rights

With the exception of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits (collectively, "leases")

for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. The provincial governments in Western Canada conduct regular land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

In response to COVID-19, the governments of Alberta, British Columbia and Saskatchewan announced measures to extend or continue Crown leases that may have otherwise expired in the months following the implementation of pandemic response measures.

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

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

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.

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. Similar rules apply to facility and pipeline operators.

Royalties and Incentives

General

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable.

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

Occasionally, the provincial governments in Western Canada create incentive programs for the oil and gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the oil and gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, including those programs created in response to the COVID-19 pandemic such as the various short-term loan programs and the Canada Emergency Wage Subsidy, for example, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, Innovation, Science and Economic Development Canada and, in some cases, the Canada Revenue Agency.

Alberta

Crown royalties

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

Royalties on production from wells subject to the Modernized Framework are determined on a "revenue-minus-costs" basis. The cost component is based on a Drilling and Completion Cost Allowance formula that relies, in part, on the industry's average drilling and completion costs, determined annually by the AER, and incorporates information specific to each well such as vertical depth and lateral length.

Under the Modernized Framework, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable Drilling and Completion Cost Allowance. After payout, producers pay an increased royalty of up to 40% that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%.

Under the Old Framework, royalty rates for conventional oil production can be as high as 40% and royalty rates for natural gas production can be as high as 36%. Similar to the Modernized Framework, these rates vary based on the nature of the resource and market prices. The natural gas royalty formula also provides for a reduction based on the measured depth of the well, as well as the acid gas content of the produced gas.

In addition to royalties, producers of oil and natural gas from Crown lands in Alberta are also required to pay annual rentals to the Government of Alberta.

Freehold royalties and taxes

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

The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

British Columbia

Crown royalties

Crown royalties payable on the production of oil and natural gas in British Columbia vary by market price, well type and the characteristics of the substances being produced. Producers of oil and natural gas receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales.

The Crown royalty rate for oil can be as high as 40% and depends on factors such as the volume of oil produced from a particular well or unitized tract and its vintage. Royalty rates are reduced on certain wells, including low-productivity wells, to reflect higher per-unit costs of exploration and extraction. The Crown royalty rate for natural gas and NGLs in British Columbia varies depending on the characteristics of the specific substance and can be as high as 27%, depending on factors such as whether the gas is classified as conservation gas or non-conservation gas, the applicable reference price and select price.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of oil and natural gas from freehold lands in British Columbia also pay monthly freehold production taxes to the Government of British Columbia.

For oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax to the Government of British Columbia.

Regulatory Authorities and 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 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 greenhouse gas ("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. The Corporation routinely conducts hydraulic fracturing in its drilling and completion programs. 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 have operations in Fox Creek, Red Deer and Brazeau. Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk of earthquakes in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") regulates conventional oil and natural gas producers, shale gas producers and other operators of oil and natural gas facilities in the province. Under the OGAA, the BC Commission has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives and requires the BC Commission to consider these environmental objectives in deciding whether or not to authorize a particular activity. In addition, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work. Such approvals are given subject to environmental considerations and permits, licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

The Government of British Columbia has introduced a regime to monitor and manage the risk of induced seismicity related to oil and natural gas operations, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The *Drilling and Production Regulation* requires a producer to suspend its operations if they trigger an earthquake with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BC Commission before resuming production. In June 2016, the BC Commission amended the permitting process to require all natural gas producers to conduct ground monitoring, and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BC Commission issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson

Creek (the "**Kiskatinaw Area**"). Permit holders in the Kiskatinaw Area are subject to additional requirements before they can conduct hydraulic fracturing operations, including developing a seismic monitoring and mitigation plan that is approved by the BC Commission, and notifying the BC Commission and local residents about planned hydraulic fracturing requirements. During active hydraulic fracturing operations, permit holders are required to deploy an accelerometer, have access to real-time seismicity readings and report such readings to the BC Commission on demand. If a seismic event occurs, permit holders are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude and triggers a sliding scale of obligations from permit holders. The obligations range from reporting the earthquake and developing an approved protocol for subsequent earthquakes, to initiating such protocols, to suspending operations until permitted to resume by the BC Commission. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

An updated *Environmental Assessment Act* came into force in December 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasises early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the *Environmental Assessment Act*, the Government of British Columbia enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the BC EAO will consider the environmental, health, cultural, social and economic effects of a proposed project.

Liability Management Rating Program

Alberta

The AER administers a Liability Management Rating Program (the "**AB LMR Program**"), which is currently undergoing changes, including a name change to the "Liability Management Framework" (the "**AB LMF**"). The AB LMR Program is a liability management program governing most conventional upstream oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LFP**"), and the Licensee Liability Rating Program (the "**AB LLR Program**"). 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 licensee, must reduce its liabilities or provide the AER with a security deposit. Failure to do so may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**").

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 program intended to address the growing inventory of inactive and noncompliant wells in Alberta. More recently, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through 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.

British Columbia

Similar to Alberta, the BC Commission oversees a Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the BC Commission determines the required security deposits for

permit holders under the OGAA. The liability management rating is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed their deemed assets (i.e., an LMR below 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

In the spring of 2019, a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the levy. The OGAA permits the BC Commission to impose more than one levy in a given calendar year.

The *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BC Commission, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in the corresponding annual work plan.

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. The Government of British Columbia is disbursing its \$120 million share of the federally provided funds through three programs: the Dormant Sites Reclamation Program, the Orphan Sites Supplemental Reclamation Program and the Legacy Sites Reclamation Program. In Saskatchewan, \$400 million in federal funding will be allocated through the Accelerated Site Closure Program ("**ASCP**"). The first phase of the ASCP will make \$100 million available to eligible service companies to conduct abandonment and reclamation work. Further tranches of the ASCP, up to \$300 million, will be made available in the future.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and gas industry in Canada. These impacts are uncertain and it is not possible to predict what future policies, laws and regulations will entail. 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

In November 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). In December 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed.

In June 2019, the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently \$30/tonne of CO₂e and will increase to \$40/tonne on April 1, 2021. In December 2019, the federal government approved Alberta's *Technology Innovation and Emissions Reduction ("TIER")* regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaces the previous *Carbon Competitiveness Incentives Regulation*.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO₂e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. 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.

British Columbia

In August 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. British Columbia was also the first Canadian province to implement a revenue-neutral fuel charge. The fuel charge is currently set at \$40/tonne of CO₂e. In response to COVID-19, the Government of British Columbia has delayed the scheduled increase to \$45/tonne of CO₂e until April 1, 2021.

In January 2016, the Greenhouse Gas Industrial Reporting and Control Act (the "**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

In December 2018, the Government of British Columbia announced an updated clean energy plan, "**CleanBC**", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction, and waste sectors of the British Columbia economy. Key initiatives include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15% renewable content requirement in natural gas by 2030; (iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (iv) investing in the electrification of oil and natural gas production; (v) reducing 45% of methane emissions associated with natural gas production; and (vi) incentivizing the adoption of zero-emissions vehicles.

In January 2019, the BC Commission announced a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules came into effect on January 1, 2020. In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the *United Nations Declaration of the Rights of Indigenous Peoples* ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In December 2020, the federal government introduced *Bill C-15: An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples Act* ("**Bill C-15**"). Similar to British Columbia's DRIPA, the intention of Bill C-15, if passed, is to establish a process whereby the Government of Canada will take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and Bill C-15 are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation'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 Corporation's business and the oil and natural gas business generally.

Exploration, Development and Production Risks

The Corporation's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able to continue to find

satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation 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 or from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies 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, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, the Corporation may explore for and produce sour gas in certain areas. An unintentional leak of sour 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 Corporation.

Oil and natural gas production operations are also subject to geological and seismic risks, 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 the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance and business interruption insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "*Risk Factors – Insurance*". In either event, the Corporation could incur significant costs.

Weakness and Volatility in the Oil and Natural Gas Industry

Weakness and volatility in the market conditions for the oil and natural gas industry may affect the value of the Corporation's reserves and restrict its cash flow and ability to access capital to fund the development of its properties

Market events and conditions, including global excess oil and natural gas supply, the ongoing coronavirus disease ("**COVID-19**") pandemic, actions taken by the Organization of the Petroleum Exporting Countries ("**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-hydrocarbon sentiment, have caused significant volatility in commodity prices. See "*Risk Factors – Political Uncertainty*" and "*Risk Factors - The 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 "*Risk Factors – Royalties and Incentives*", "*Risk Factors – Regulatory Authorities and Environmental Regulation*" and "*Risk Factors – 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"*. 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 – Additional Funding Requirements"*.

Impact of Pandemics

The COVID-19 pandemic may effect the Corporation's results, business, financial conditions or liquidity

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;

- crude oil storage constraints 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.

Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities

The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity in pipelines that deliver oil, NGLs and natural gas to commercial markets or contract for the delivery of crude oil and NGLs by rail. Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation, including:

- deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines and processing and storage facilities;
- operational problems affecting pipelines, railway lines and processing and storage facilities; and
- government regulation relating to prices, taxes, royalties, land tenure, allowable production and the export of oil and natural gas.

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 Marketing*" and "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

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.

Market Price

The trading price of the Corporation's Common Shares may be adversely affected by factors related and unrelated to the oil and natural gas industry

The trading price of the 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 Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, and/or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. Similarly, the market price of the Common Shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved and the Corporation may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions

The Corporation 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 Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses and assets 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 the resources required to provide such services. In this regard, non-core assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the market conditions for such non-core assets, certain non-core assets of the Corporation may realize less on disposition than their carrying value on the financial statements of the Corporation.

Political Uncertainty

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

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During its tenure, the former American administration withdrew the United States from the Trans-Pacific Partnership and passed sweeping tax reform, which, among other things, significantly reduced U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The former U.S. administration also took action to reduce regulation, which affected relative competitiveness of other jurisdictions.

In addition, the United States Mexico Canada Agreement (the "USMCA"), which replaced the former North American Free Trade Agreement ("NAFTA") was ratified on July 1, 2020 and may impact the Corporation's business. See *"Industry Conditions – The North American Trade Agreement and Other Trade Agreements"*.

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 changing political landscape in the United States, the impact of the United Kingdom's exit from the European Union are slowly emerging and some impacts may not become apparent for some time. 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.

The United Conservative Party government in Alberta is supportive of the Trans Mountain Pipeline expansion project and, although there has been notable opposition from the government of British Columbia, the federal Government remains in support of the project. 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 where the Corporation is active. See *"Industry Conditions – Transportation Constraints and Market Access"* and *"Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia"*.

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"*.

Operational Dependence

The successful operation of a portion of the Corporation's properties is dependent on third parties

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation'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 volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation 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 Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, the Corporation 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 Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse effect on the Corporation's financial and operational results. See "*Industry Conditions – Liability Management Rating Program*" and "*Risk Factors – Third Party Credit Risk*".

Reliance on Royalty Payors

A portion of the Corporation's revenues from royalty payors and certain of its operations are dependent on the financial and operational capacity of third party working interest owners to develop and produce from the Corporation's properties, over which it has limited influence

The Corporation relies on other companies drilling and producing from lands in which the Corporation has a royalty interest. The Corporation has very limited ability to exercise influence over the decision of companies to drill and produce from such lands. The Corporation's return on lands in which it has a royalty interest depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the capital expenditure budgets and financial resources of the operators who have a working interest in such lands, the ability to efficiently produce the resources from such lands and commodity prices.

In addition, due to unstable commodity prices, many companies, including companies that may have a working interest in the lands in which the Corporation has a royalty interest, may be in financial difficulty, which could affect their ability to fund and pursue capital expenditures on such lands. Furthermore, weak commodity prices and/or curtailment of the production of crude oil mandated by the Government of Alberta may result in companies choosing to defer capital spending or shutting-in existing production. See "*Industry Conditions – Curtailment*". Any reduction in the drilling and production from lands in which the Corporation has a royalty interest will negatively affect the Corporation's cash flows and financial results.

Financial difficulty of companies who have lands in which the Corporation has a royalty interest may affect the Corporation's ability to collect royalty payments, especially if such companies go bankrupt, become insolvent, or make a proposal or institute any proceedings relating to bankruptcy or insolvency.

Project Risks

The success of the Corporation's operations may be negatively impacted by factors outside of its control resulting in operational delays and cost overruns

The Corporation manages a variety of small and large projects in the conduct of its business. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The Corporation's ability to execute projects and to market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour; and
- regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all.

Gathering and Processing Facilities, Pipeline Systems and Rail

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on the Corporation's ability to produce and sell its oil and natural gas

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. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on inter-provincial 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. In August 2019, the CERA and the IAA came into force, resulting in changes to the federal regulation and associated environmental assessments of major projects. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

In January 2021, U.S President Biden took steps to cancel the presidential permit that had allowed the Keystone XL Pipeline to operate across Canadian and American borders. It is unclear if challenges to the revocation of the permit will be successful and what the direct impact of the loss of permit will be on the Corporation.

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.

Competition

The Corporation competes with other oil and natural gas companies, some of which have greater financial and operational resources

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. The Corporation'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, process, and reliability of delivery and storage.

Cost of New Technologies

The Corporation's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete

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 implement and benefit from technological advantages. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis, or at an acceptable cost. If the Corporation does implement such technologies, there is no assurance that the Corporation will do so successfully. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. If the Corporation is unable to utilize the most advanced commercially available technology, or is unsuccessful in implementing certain technologies, its business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Corporation's financial condition, results of operations and cash flow

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 systems could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of hydrocarbons and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural 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 flow by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Regulatory

Modification to current, or implementation of additional, regulations may reduce the demand for oil and natural gas and/or increase the Corporation's costs and/or delay planned operations

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 the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations

and prospects. 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. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations"*, *"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 – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs"*.

Royalty Regimes

Changes to royalty regimes may negatively impact the Corporation's cash flows

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. See *"Industry Conditions – Royalties and Incentives"*.

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Corporation's financial position

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation'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 Corporation is ultimately able to produce from its reserves.

Alberta

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, Rocky Mountain House, Brazeau and Red Deer. Since 2015, the Alberta Energy Regulator ("**AER**") has introduced seismic protocols for hydraulic fracturing operators in the Fox Creek, Red Deer and Brazeau areas (collectively, the "**Seismic Protocol Regions**")—initially in response to significant induced seismic activity in the Duvernay formation in Fox Creek in February 2015. Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude which vary among the three regions. The reporting requirements include 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, depending on the magnitude of an earthquake. Orders imposed by the AER in response to seismic events remain in effect as long as the AER deems them necessary. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, leading to continued monitoring by the AER. The AER may extend seismic protocols to other areas of the province if necessary.

See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta*".

British Columbia

Due to seismic activity recorded in the Kiskatinaw Seismic Monitoring and Mitigation area (the "**Kiskatinaw Area**"), in May 2018, the British Columbia Oil & Gas Commission (the "**BC Commission**") These requirements include, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations, pre-operation notification to both residents and the BC Commission and the suspension of operations if a seismic event above a 3.0 magnitude occurs.

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how British Columbia's regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. The implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect the Corporation's business operations, financial condition, results of operations and prospects.

See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams companies have built in association with their hydraulic fracturing operations. These requirements are outlined in provincial legislation, namely the *Water Sustainability Act* and the *Dam Safety Regulation*. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the requisite regulatory authorization. The BC Commission has issued compliance orders with respect to individual dams, but it remains uncertain how, and to what extent the relevant industry regulators will respond to this issue. The Corporation may face operational delays depending on the level of severity with which the overseeing regulatory authorities decide to address these unauthorized projects, particularly where the Corporation is not strictly complying with the current regulatory framework.

Waterflood

Regulatory water use restrictions and/or limited access to water or other fluids may impact the Corporation's production volumes from its waterflood

The Corporation undertakes or intends to undertake 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 Corporation 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 Corporation 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 Corporation 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 Corporation is ultimately able to produce from its reservoirs. In addition, the Corporation 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 Corporation's results of operations.

Disposal of Fluids used in Operations

Regulations regarding the disposal of fluids used in the Corporation's operations may increase its costs of compliance or subject it to regulatory penalties or litigation

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.

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Corporation's financial and operational resources

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 and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. New environmental legislation at the federal and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements 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 Corporation's business, financial condition, results of operations and prospects.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system applies in provinces and territories that request it to be implemented or are without their own system that meets federal standards. The federal regime was subject to a number of court challenges by Alberta, Saskatchewan and Ontario. The final decision from the Supreme Court of Canada is expected to be delivered sometime in 2021. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". Any 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 Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Corporation's ability to acquire properties or require a substantial cash deposit with the regulator

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of

wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Changes to the Liability Management Rating Program (the "**AB LMR Program**") administered by the AER are currently underway. In July 2020, the Government of Alberta announced that the AB LMR and associated programs will be replaced by the "Liability Management Framework" (the "**AB LMF**"). Other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in Redwater on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. As a result of the decision, the Government of Alberta implemented the *Liabilities Management Statutes and Amendment Act*, which places the financial burden of a defunct licensee's abandonment and reclamation obligations on the working interest partners of the defunct Licensee and may order the AER's Orphan Fund to assume custody of wells or sites without a responsible owner to expedite the cleanup process.

In addition, the AB LMF Program may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

Climate change may pose varied and far ranging risks to the business and operations of the Corporation, both known and unknown, that may adversely affect the Corporation's business, financial condition, results of operations, prospects, reputation and share price

Chronic Climate Change Risks

The Corporation's exploration and production facilities and other operations and activities emit GHGs which may require the Corporation to comply with federal and/or provincial GHG 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*". 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 hydrocarbon 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 recent years, climate change advocacy groups have attempted to bring legal action against various levels of government for climate-related harms.

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, potentially reducing the 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 – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations*", "*Risk Factors – Reputational Risk Associated with the Corporation's Operations*" and "*Risk Factors – Changing Investor Sentiment*".

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Corporation's assets are located in locations that are proximate to forests/rivers and a wildfire/flood may lead to significant downtime and/or damage to such assets.

Moreover, extreme weather conditions may lead to disruptions in the Corporation's ability to transport produced oil and natural gas as well as goods and services in its supply chain.

Seasonality

Oil and natural gas operations are subject to seasonal weather conditions and the Corporation may experience significant operational delays as a result

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 which prevents, delays or makes operations more difficult. Consequently, municipalities and provincial transportation departments may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road 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 of the Corporation's 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 impassable muskeg.

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Corporation's financial condition

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States 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 relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Corporation's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Corporation receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results.

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

An increase in interest rates could result in a significant increase in the amount the Corporation 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. Such an increase could also negatively impact the market price of the Common Shares of the Corporation.

Substantial Capital Requirements

The Corporation's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations and acquire and develop reserves

The Corporation 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, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating;
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

See "*Industry Conditions – Royalties and Incentives*".

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including the Corporation, to access additional financing and/or the cost thereof. 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 Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation may require additional financing, from time to time, to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and, from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Corporation may, from time to time, have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access, or the cost of, additional financing.

As a result of global economic and political conditions and the domestic lending landscape, the Corporation may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain suitable financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's 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 Corporation'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 Corporation'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. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

Failing to comply with covenants under the Corporation's credit facility could result in restricted access to additional capital or being required to repay all amounts owing thereunder

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which, from time to time, either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Supreme Court of Canada's decision in Redwater has give rise to new covenants and restrictions under the Corporation's credit facilities, 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. See also "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

If the Corporation's lenders require repayment of all or a portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that the Corporation would be in a position to make such repayment. Even if the Corporation 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 Corporation. If the Corporation is unable to repay amounts owing under its credit facilities, the lenders under such credit facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Issuance of Debt

Increased debt levels may impair the Corporation's ability to borrow additional capital on a timely basis to fund opportunities as they arise

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

Hedging

Hedging activities expose the Corporation to the risk of financial loss and counter-party risk

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation 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 Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- 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, the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Corporation will not benefit from the fluctuating exchange rate.

Availability and Cost of Material and Equipment

Restrictions on the availability and cost of materials and equipment may impede the Corporation's exploration, development and operating activities

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Corporation's exploration, development and operating activities.

Diluent Supply

A decrease in, or restriction in access to, diluent supply may increase the Corporation's operating costs

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent, or a restriction in access to diluent, may cause its price to increase, increasing the cost to transport heavy oil

and bitumen to market. An increase to the cost of bringing heavy oil and bitumen to market may increase the Corporation's overall operating cost and result in decreased net revenues, negatively impacting the overall profitability of the Corporation's heavy oil and bitumen projects.

Title to and Right to Produce from Assets

Defects in the title or rights to produce the Corporation's properties may result in a financial loss

The Corporation's actual title to and interest in its properties, and its right to produce and sell the oil and natural gas therefrom, may vary from the Corporation's records. In addition, there may be valid legal challenges or legislative changes that affect the Corporation's title to and right to produce from its oil and natural gas properties, which could impair the Corporation's activities and result in a reduction of the revenue received by the Corporation.

If a defect exists in the chain of title or in the Corporation's right to produce, or a legal challenge or legislative change arises, it is possible that the Corporation may lose all, or a portion of, the properties to which the title defect relates and/or its right to produce from such properties. This may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reserves Estimates

The Corporation's estimated reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Corporation

There are numerous uncertainties inherent in estimating reserves and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves (including the breakdown of reserves by product type) and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- 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. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates 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 are often 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 and such variations could be material.

In accordance with applicable securities laws, the Corporation'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 the Corporation'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 Corporation 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 therefore does not reflect changes in the Corporation's reserves since that date.

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Corporation

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

Non-Governmental Organizations

The Corporation's properties may be subject to action by non-governmental organizations or terrorist attack

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 from 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. See "*Industry Conditions – Transportation Constraints and Market Access*". 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.

Reputational Risk Associated with the Corporation's Operations

The Corporation relies on its reputation to continue its operations and to attract and retain investors and employees

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 hydrocarbon 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.

Changing Investor Sentiment

Changing investor sentiment towards the oil and natural gas industry may impact the Corporation's access to, and cost of, capital

A number of factors, including the effects of the use of hydrocarbons on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in oil and natural gas properties or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, management and employees of the 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 natural 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 asset which may result in an impairment change.

Dilution

The Corporation may issue additional Common Shares, diluting current shareholders

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.

Management of Growth

The Corporation may not be able to effectively manage the growth of its business

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation 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. If the Corporation is unable to deal with this growth, it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licenses and Leases

The Corporation, or its working interest partners, may fail to meet the requirements of a licence or lease, causing its termination or expiry

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

Dividends

The amount of future cash dividends paid by the Corporation, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Corporation, the dividend policy of the Corporation from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

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

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

Litigation

The Corporation may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Corporation and its reputation

In the normal course of the Corporation'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. Potential litigation may develop in relation to personal injuries (including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes). The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation 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 affect on the Corporation's financial condition.

Intellectual Property Litigation

Unauthorized use of intellectual property may cause the Corporation to engage in, or be the subject of, litigation

Due to the rapid development of oil and natural gas technology, in the normal course of the Corporation's operations, the Corporation may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that the Corporation has infringed the intellectual property rights of others or which the Corporation initiates against others it believes are infringing upon its intellectual property rights. The Corporation's involvement in intellectual property litigation could result in significant expense, adversely affecting the development of its assets or intellectual property or diverting the efforts of its technical and management personnel, whether or not such litigation is resolved in the Corporation's favour. In the event of an adverse outcome as a defendant in any such litigation, the Corporation may, among other things, be required to:

- (a) pay substantial damages and/or cease the development, use, sale or importation of processes that infringe upon other patented intellectual property;
- (b) expend significant resources to develop or acquire non-infringing intellectual property;
- (c) discontinue processes incorporating infringing technology; or
- (d) obtain licences to the infringing intellectual property.

However, the Corporation may not be successful in such development or acquisition, or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on the Corporation's business and financial results.

Indigenous Claims

Indigenous claims may affect the Corporation

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.

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Corporation's competitive advantage or put it at risk of litigation

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to its business, operations or affairs. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation 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.

Income Taxes

Taxation authorities may reassess the Corporation's tax returns

The Corporation files 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. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

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

Third Party Credit Risk

The Corporation is exposed to credit risk of third party operators or partners of properties in which it has an interest

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 petroleum and natural gas 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, generally, and of the Corporation's 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.

Conflicts of Interest

Conflicts of interest may arise for the Corporation's directors and officers who are also involved with other industry participants

Certain directors or officers of the Corporation 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 Corporation 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*".

Reliance on a Skilled Workforce and Key Personnel

An inability to recruit and retain a skilled workforce and key personnel may negatively impact the Corporation

The operations and management of the Corporation require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Corporation's business plans which could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. The Corporation does not have any key personnel insurance in effect. Contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, certain of the Corporation's current employees are senior and have significant institutional 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.

Information Technology Systems and Cyber-Security

Breaches of the Corporation's cyber-security and loss of, or access to, electronic data may adversely impact the Corporation's operations and financial position

The Corporation is 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 the Corporation's land base, manage financial resources, analyze seismic information, administer contracts with 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 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 business activities or the Corporation's 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 ongoing COVID-19 pandemic has increased the Corporation's cyber-attacks, as increased malicious activities are creating more threats for cyberattacks including COVID-19 phishing emails, malware-embedded mobile apps that purport to track infection rates, and targeting of vulnerabilities in remote access platforms as many companies continue to operate with work from home arrangements.

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 the Corporation's performance and earnings, as well as its 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.

Social Media

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

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

Expansion into New Activities

Expanding the Corporation's business exposes it to new risks and uncertainties

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

Forward-Looking Information

Forward-looking information may prove inaccurate

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, assumptions and uncertainties are found under the heading "*Forward-Looking Statements*".

AUDIT COMMITTEE INFORMATION

The Audit Committee has been structured to comply with the requirements of National Instrument 52-110. The Board has determined that the Audit Committee members have the appropriate level of financial understanding and industry-specific knowledge to be able to perform their duties. A copy of the Audit Committee mandate and the additional disclosure required under National Instrument 52-110 is attached to this Annual Information Form as Schedule "C".

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR 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 is contained in the Company's information circular for the Company's most recent annual meeting of securityholders that involved the election of directors. Additional financial information is contained in the Financial Statements and the MD&A for the Company's most recently completed financial year.

SELECTED ABBREVIATIONS

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

Crude Oil and Natural Gas Liquids

Bbls/d	barrels of oil per day
Bbls or Bbl	barrels of oil
Boe	barrel of oil equivalent
Boe/d	barrel of oil equivalent per day
\$/Bbl	Canadian dollars per barrel of oil
\$/Boe	Canadian dollars per barrel of oil equivalent
Mbbls	thousand barrels
MBoe	thousand barrels of oil equivalent
Mbbls/d	thousand barrels of oil per day
MMbbls	million barrels of oil
MMboe	million barrels of oil equivalent
MMboe/d	million barrels of oil equivalent per day
NGL	natural gas liquids

Natural Gas

Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
cf	cubic feet
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
Mcfe	thousand cubic feet of gas equivalent
Mcfe/d	thousand cubic feet of gas equivalent per day
MMbtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMcfe	million cubic feet of gas equivalent
MMcfe/d	million cubic feet of gas equivalent per day
\$/Mcf	Canadian dollars per thousand cubic feet
\$/MMbtu	Canadian dollars per million British thermal units
GJ	Gigajoule
GJs/d	Gigajoules per day
\$/GJ	Canadian dollar per gigajoule

Other

km	Kilometres
km ²	square kilometres
\$, \$Cdn, Cdn\$ or \$dollars	Canadian dollars
\$000s or M\$	thousand dollars
NEBC	north east British Columbia

MM\$.....	million dollars
\$US or US\$.....	United States dollars
2D.....	two dimensional
3D.....	three dimensional
Vol/d.....	volumes per day

SELECTED CONVERSIONS

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

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
Mcf	cubic metres	28.320
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

FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form constitute forward-looking statements. These statements relate to future events or the Company's 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 Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form. In addition, this Annual Information Form may contain forward-looking statements and forward-looking information attributed to third-party industry sources.

In particular, this Annual Information Form contains, without limitation, forward-looking statements pertaining to the following:

- the reserve potential of the Company's assets;
- the production from the Company's assets;
- the Company's growth strategy and opportunities;
- the ability to achieve an appropriate level of quarterly cash dividends;
- the Company's capital exploration and development programs and future capital requirements;
- 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 Company's environmental considerations;
- the Company's expectations regarding commodity prices;
- the timing of commencement of certain of the Company's operations and the level of production anticipated by the Company;
- the potential for production disruption and constraints;
- supply and demand fundamentals for crude oil and natural gas;
- the Company's access to adequate pipeline capacity;
- the Company's access to third-party infrastructure;
- the Company's drilling and recompletion plans and abandonment and reclamation costs;
- industry conditions pertaining to the oil and gas industry;
- the Company's plans for, and results of, exploration and development activities;
- the planned construction of the Company's gathering, transportation and processing facilities and related infrastructure;
- the timing for receipt of regulatory approvals;
- the Company's treatment under governmental regulatory regimes and tax laws;
- the Company's expectations regarding having adequate human resource staffing;
- the Company's dividend policy; and
- the number of wells to be drilled and drilling rigs to be operated by the Company in 2021.

With respect to forward-looking statements and forward-looking information contained in this Annual Information Form, assumptions have been made regarding, among other things:

- future crude oil 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;
- 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 Annual Information Form, including:

- operating and capital costs;
- the Company's status and stage of development;
- general economic, market and business conditions;
- volatility in market prices for crude oil and natural gas and hedging activities related thereto;
- risks related to the exploration, development and production of oil and natural 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;
- 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;
- 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;
- hedging strategies;
- potential conflicts of interest;
- the potential for management estimates and assumptions to be inaccurate;
- additional indebtedness;
- volatility in the market price of the Common Shares of the Company;
- the absence of an existing public market for the Common Shares;
- the effect that the issuance of additional securities by the Company could have on the market price of the Common Shares;
- 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;
- current global financial conditions, including fluctuations in interest rates, foreign exchange rates and stock market volatility; and
- the other factors discussed under "*Risk Factors*" in this Annual Information Form.

Without limitation of the foregoing, future dividend payments, if any, and the level thereof is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time will be dependent upon, among other things, free cash flow, financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of Tourmaline to pay dividends will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility.

Forward looking statements and other information contained herein concerning the oil and gas industry and the Company's general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. The industry involves risks and uncertainties and is subject to change based on various factors.

In addition, information and statements in this Annual Information Form 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 "*Certain Reserves Data Information*" below. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive.

Additional information on these and other factors that could affect Tourmaline's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

The forward-looking statements included in this Annual Information Form are expressly qualified by this cautionary statement and are made as of the date of this Annual Information Form. The Company does not undertake any obligation to publicly update or revise any forward-looking statements except as expressly required by applicable securities laws.

NON-GAAP FINANCIAL MEASURES

This Annual Information Form and certain documents incorporated by reference herein make reference to certain financial measures that are not recognized by GAAP. Non-GAAP financial measures do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures presented by other issuers. Investors are cautioned that these non-GAAP financial measures should not be construed as alternatives to other measures of financial performance calculated in accordance with GAAP. For information regarding the non-GAAP financial measures used by Tourmaline, see "Non-GAAP Financial Measures" in Tourmaline's MD&A for the year ended December 31, 2020, which section is incorporated by reference herein. The Financial Statements and MD&A are available on SEDAR at www.sedar.com.

CERTAIN RESERVES DATA INFORMATION

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 of proved, probable and possible reserves 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 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent 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 nonproducing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

In this Annual Information Form:

- (a) the discounted and undiscounted net present value of future net revenues attributable to reserves do not represent the fair market value of reserves;
- (b) 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, NGL and natural gas reserves

provided in this Annual Information Form are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGL reserves may be greater than or less than the estimates provided in this Annual Information Form;

- (c) the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation; and
- (d) Boes 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 that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

DRILLING LOCATIONS

This document discloses drilling locations, as at December 31, 2020, in four categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii). Of the 20,014 (gross) locations, 1,375 are proved undeveloped locations, 25 are proved non-producing locations, 1,179 are probable undeveloped locations and 17,435 are unbooked locations. Proved undeveloped locations, proved non-producing locations, probable undeveloped locations and probable non-producing locations are booked and derived from the Consolidated Reserve Report and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

SCHEDULE "A"

FORM 51-101F2

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Tourmaline Oil Corp. (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:

<u>Independent Qualified Reserves Evaluator or Auditor</u>	<u>Effective Date of Evaluation Report</u>	<u>Location of Reserves (Country or Foreign Geographic Area)</u>	<u>Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - \$MM)</u>			
			<u>Audited</u>	<u>Evaluated</u>	<u>Reviewed</u>	<u>Total</u>
Deloitte LLP	December 31, 2020	Canada	-	\$2,439.8	-	\$2,439.8
GLJ Ltd.	December 31, 2020	Canada	-	\$14,732.3	-	\$14,732.3
*GLJ Ltd.	December 31, 2020		-	\$51.1	-	\$51.1
Total			-	\$17,223.2	-	\$17,223.2

*Additional value attributed by GLJ Ltd. is associated with Company level adjustments not directly attributable to individual assets. This includes items such as physical sales contracts outside of Western Canada and abandonment and reclamation liabilities attributed to inactive assets.

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 judgements regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above.

GLJ Ltd., Calgary, Alberta, Canada, March 1, 2021.

ORIGINALLY SIGNED BY

"Originally signed by"

**Chad P. Lemke, P. Eng.
Executive Vice President and COO**

Deloitte, Calgary, Alberta, Canada, March 1, 2021.

ORIGINALLY SIGNED BY

"Originally signed by"

**Andrew Botterill, P. Eng.
Partner, Resource Evaluation and Advisory**

SCHEDULE "B"

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

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

GLJ Ltd. and Deloitte LLP, each an independent qualified reserves evaluator, has evaluated the Company's reserves data. The reports of the independent qualified reserves evaluator are presented below.

The Reserves Committee of the board of directors of the Company has

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

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-102F2 which is the reports of the independent qualified reserves evaluators on the reserves data, contingent resources data, or prospective resources data; and
- (c) the content and filing of this report.

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

DATED as of this 10th day of March, 2021.

(signed) "Michael L. Rose"
Michael L. Rose
President, Chief Executive Officer and
Director

(signed) "Brian G. Robinson"
Brian G. Robinson
Vice President, Finance and Chief Financial
Officer

(signed) "Andrew B. MacDonald"
Andrew B MacDonald
Director

(signed) "Lee A. Baker"
Lee A. Baker
Director

SCHEDULE "C"

AUDIT COMMITTEE MANDATE AND AUDIT COMMITTEE DISCLOSURE

AUDIT COMMITTEE MANDATE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Tourmaline Oil Corp. ("**Tourmaline**" or the "**Company**") to which the Board has delegated its responsibility for the oversight of the following:

1. nature and scope of the annual audit;
2. the oversight of management's reporting on internal accounting standards and practices;
3. the review of financial information, accounting systems and procedures;
4. 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 of Tourmaline ("**Directors**") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Company and related matters, including compliance with legal and regulatory requirements;
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, the financial reporting process and internal controls over financial reporting;
5. To strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management of Tourmaline ("**Management**") and external auditors;
6. To maintain oversight of risk identification, assessment and management programs; and
7. To establish procedures for the receipt, retention and treatment of complaints received by the Company regarding accounting, internal controls or auditing matters.

Membership of Committee

1. The Board, on recommendation of the Governance Committee, will appoint members to the Committee. The Committee will be comprised of at least three (3) Directors 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 ("**NI 52-110**") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.

2. The Board, on recommendation of the Governance Committee, 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 Tourmaline's internal control systems; identify, monitor and mitigate business risks; and ensuring compliance with legal, ethical and regulatory requirements.
3. Review the annual and interim financial statements of the Company 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;
 - obtaining explanations of significant variances with comparative reporting periods; and
 - determining through inquiry if there are any related party transactions and ensuring that the nature and extent of such transactions are properly disclosed.
4. In addition to the review of financial statements and MD&A described above, review prospectuses, 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 Tourmaline'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;
 - monitor the relationship between management and the external auditor including reviewing any management letters or other reports of the external auditor and discussing any material differences of opinions between management and the external auditor;

- 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 Tourmaline 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 Tourmaline) their assessment of the internal controls of Tourmaline, 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 Tourmaline and its subsidiaries.
7. Review risk management policies and procedures of the Company (i.e., hedging, litigation, third party credit risk and insurance). In this regard, the Committee shall:
- Regularly identify and review the principal business risks, including potential emerging risks, of the Company and the actions taken by the Company to mitigate the risks;
 - Regularly identify and review the principal financial risks and exposures of the Company, together with mitigating strategies, including physical and financial positions in commodities markets, derivatives strategies, capital commitments, foreign exchange exposures, and exposure to interest rate fluctuations;
 - Regularly review the policies and activities of the Company's treasury and marketing groups and the financial risks arising from those activities, including any proposed authorities of Management from the Board for the hedging of the exposures; and
 - Review, and if desirable, recommend changes to the insurance program including coverage for property damage, business interruption and liabilities.
8. Establish a procedure for:
- the receipt, retention and treatment of complaints received by Tourmaline regarding accounting, internal accounting controls or auditing matters; and
 - the confidential, anonymous submission by employees of Tourmaline of concerns regarding questionable accounting or auditing matters.
9. Review and approve Tourmaline's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Company.

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 Tourmaline. All employees of Tourmaline 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 Tourmaline without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote and in such cases, the undecided matter should be referred to the Board as a whole.

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 of Tourmaline 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 and its subsidiaries 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. At each meeting, the Committee will meet in camera without management present.
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 as determined by the Committee.
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.
12. In discharging its duties under this Mandate, the Committee may investigate any matter brought to its attention and will have access to all books, records, facilities and personnel, may conduct meetings or interviews of any officer or employee, the Company's legal counsel, external auditors and consultants and may invite any such other persons to attend any part of any meeting of the Committee.

AUDIT COMMITTEE DISCLOSURE

Audit Committee Mandate and Terms of Reference

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 and terms of reference is set forth above.

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee consists of Ms. Angevine (Chair) and Messrs. MacDonald and Wigham. Each of the members of the Audit Committee is considered "financially literate" and each are considered "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 reserves; (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*" in this Annual Information Form.

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

The Audit Committee is expected to adopt specific policies and procedures for the engagement of non-audit services, as described in the mandate of the Audit Committee.

External Audit Service Fees

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

Year	Audit Fees ⁽¹⁾	Audit – Related Fees ⁽²⁾	Tax Fees ⁽³⁾	All Other Fees ⁽⁴⁾
	(\$)	(\$)	(\$)	(\$)
2020.....	1,744,100	107,000	158,360	–
2019.....	1,230,000	100,000	13,920	250,000 ⁽⁵⁾
2018.....	1,200,000	100,000	18,945	–

Notes:

- (1) Represents the aggregate fees billed by the Company's external auditor in each of the last three fiscal years for services that are reasonably related to the performance of the audit or review of the Company's financial statements. The fees disclosed under this category also include the conduct of due diligence procedures in connection with financings and acquisitions undertaken by the Company.
- (2) Represents the aggregate fees related to the French translation of the annual and quarterly financial statements and MD&A.
- (3) Represents the aggregate fees billed in each of the last three fiscal years by the Company's external auditor for professional services for tax compliance, tax advice and tax planning. The services comprising the fees disclosed under this category consisted of tax consultations and tax compliance services.
- (4) Represents the aggregate fees billed in each of the last three fiscal years by the Company's external auditor for products and services not included under the headings "Audit Fees", "Audit Related Fees" and "Tax Fees".
- (5) Represents fees billed by the Company's external auditor related to a royalty recovery audit engagement.

Fees billed to Topaz Energy Corp:

<u>Year</u>	<u>Audit Fees⁽¹⁾</u>	<u>Audit – Related Fees⁽²⁾</u>	<u>Tax Fees⁽³⁾</u>	<u>All Other Fees⁽⁴⁾</u>
	<u>(\$)</u>	<u>(\$)</u>	<u>(\$)</u>	<u>(\$)</u>
2020.....	1,348,200	81,855	–	–
2019.....	–	–	–	–
2018.....	–	–	–	–

Notes:

- (1) Represents the aggregate fees billed by the Company's external auditor for services that are reasonably related to the performance of the audit or review of the Topaz financial statements. The fees disclosed under this category include the audit of the Topaz financial statements as at December 31, 2020 and for the year then ended, the audited financial statements as at June 30, 2020 and December 31, 2019 and for the six month periods ended June 30, 2020 and 2019 and for the year ended December 31, 2019 and the audit of the Operating statements for the three years ended December 31, 2019, 2018 and 2017, included in the initial public offering of Topaz. The fees also included the conduct of due diligence procedures in connection with the initial public offering and acquisitions undertaken by Topaz.
- (2) Represents the aggregate fees related to the French translation of the annual and quarterly financial statements and MD&A.
- (3) Represents the aggregate fees billed in each of the last three fiscal years by the Company's external auditor for professional services for tax compliance, tax advice and tax planning. The services comprising the fees disclosed under this category consisted of tax consultations and tax compliance services.
- (4) Represents the aggregate fees billed in each of the last three fiscal years by the Company's external auditor for products and services not included under the headings "Audit Fees", "Audit Related Fees" and "Tax Fees".