TOURMALINE
OIL CORP.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2016

March 7, 2017

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SCHEDULES

CONVENTIONS

Unless otherwise indicated, any reference in this Annual Information Form to "**Tourmaline**" or the "**Company**" 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 (Revised) – *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, 2016. All dollar amounts herein are in Canadian dollars, unless otherwise stated. See "*Selected Abbreviations*", "*Selected Conversions*", "*Forward-Looking Statements*" and "*Certain Reserves Data Information*".

CORPORATE STRUCTURE

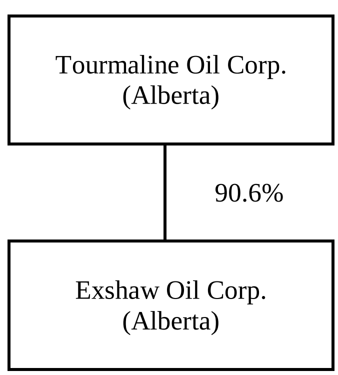
Name, address and incorporation

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



DESCRIPTION OF THE BUSINESS

Overview

Tourmaline is a Canadian senior crude oil and natural gas exploration and production company focused on long-term growth 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 intermediate 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 approximately 235,000 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 Regional Charlie Lake.

To date, the Company has raised approximately $3.9 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. In Tourmaline's view, striving to be a low cost operator is especially important in the current commodity price environment.

Business Strategy

Tourmaline's long-term business strategy is to increase shareholder value by building an extensive asset base over 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; enhancing returns by focusing on operational and cost efficiencies; pursuing strategic acquisitions with significant potential synergies; and undertaking wildcat exploration drilling for new pool discoveries.

General Development of the Business

2014

On February 12, 2014, Tourmaline completed a public offering of 4,600,000 Common Shares and a concurrent private placement of 15,198 Common Shares at a price of $47.50 per Common Share for aggregate gross proceeds of approximately $219.2 million.

On April 24, 2014, the Company completed the acquisition of Santonia with the issuance of 3,228,234 Common Shares with a closing price on that date of $54.94 per Common Share, for consideration of $177.4 million. The Company also assumed Santonia's net debt of $40.6 million, which included $8.9 million in transaction costs.

On June 2, 2014, Tourmaline completed a private placement of 1,150,000 "flow-through" Common Shares at a price of $68.15 per "flow-through" Common Share for aggregate gross proceeds of approximately $78.4 million.

On November 28, 2014, Tourmaline completed a private placement of 280,053 "flow-through" Common Shares at a price of $57.00 per share for aggregate gross proceeds of approximately $16.0 million.

On December 23, 2014, Tourmaline completed a disposition of 25% of its Peace River High Regional Charlie Lake resource play for gross proceeds of $500 million. The sale included production, reserves, facilities and undeveloped land. Concurrently, Tourmaline also entered into a long term joint-venture agreement with the purchaser to optimize the development and future value of the asset.

2015

On March 12, 2015, Tourmaline completed a private placement of 640,000 "flow-through" Common Shares at a price of $50.00 per "flow-through" Common Share for aggregate gross proceeds of approximately $32.0 million.

On April 1, 2015, the Company acquired Perpetual Energy Inc.'s ("**Perpetual**") interests in the West Edson area of the Alberta Deep Basin with the issuance of 6,750,000 Common Shares at a price of $38.32 per Common Share for total consideration of $258.7 million. The interests included Perpetual's land interests, production, reserves and facilities that were jointly-owned with Tourmaline.

On June 23, 2015, Tourmaline completed a public offering of 4,887,500 Common Shares and a concurrent private placement of 60,000 Common Shares at a price of $39.50 per Common Share for aggregate gross proceeds of approximately $195.4 million.

On July 20, 2015, the Company completed the acquisition of Bergen with the issuance of 725,000 Common Shares with a closing price on that date of $33.90 per Common Share, for consideration of $24.6 million. Transaction costs were $0.2 million. The Company also assumed Bergen's net debt of $8.4 million.

On August 14, 2015, the Company completed the acquisition of Mapan with the issuance of 2,718,026 Common Shares with a closing price on that date of $32.98 per Common Share, for consideration of $89.6 million. Transaction costs were $1.1 million. The Company also assumed Mapan's working capital of $15.0 million.

On November 25, 2015, Tourmaline completed a private placement of 482,700 "flow-through" Common Shares at a price of $34.10 per Common Share for aggregate gross proceeds of approximately $16.5 million.

2016

On January 29, 2016, Tourmaline acquired assets in the Minehead-Edson-Ansell area of the Alberta Deep Basin for cash consideration of $183.0 million. The acquisition resulted in an increase in lands, production, reserves and facilities in a core area of the Alberta Deep Basin

On April 5, 2016, Tourmaline completed a public offering of 10,350,000 Common Shares and a concurrent private placement of 37,500 Common Shares at a price of $27.11 per Common Share for aggregate gross proceeds of approximately $281.6 million.

On May 17, 2016, Tourmaline completed a private placement of 1,320,000 "flow-through" Common Shares at a price of $35.50 per Common Share for aggregate gross proceeds of approximately $46.9 million.

On October 20, 2016, Tourmaline completed a private placement of 890,500 "flow-through" Common Shares at a price of $44.50 per Common Share for aggregate gross proceeds of approximately $39.6 million.

On November 10, 2016, Tourmaline completed a public offering of 3,309,700 subscription receipts and a concurrent private placement of 18,449,000 subscription receipts at a price of $34.75 per subscription receipt for aggregate gross proceeds of approximately $756.1 million.

On November 30, 2016, the Company acquired strategic assets located in the Alberta Deep Basin and the North East British Columbia Gundy area from Shell Canada Energy for total consideration of $1.368 billion, including cash consideration of $1.0 billion and 10,017,938 Tourmaline common shares (the "**Shell Acquisition**"). In connection with the Shell Acquisition, the 21,758,700 subscription receipts previously issued were exchanged into 21,758,700 Common Shares in accordance with their terms.

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 (MM$)[1]	Production[2] (Boe/d)	Undeveloped Land Gross Acres	Undeveloped Land 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
			$3,411.6	**68,260**	**1,718,900**	**1,148,618**

Notes:

(1) These amounts reflect the purchase price paid in cash and/or Common Shares and associated transaction costs.
(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.

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[27]	
	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%
	185,258,275	**$3,944,044,406**	**$375,225,540**	**9.5%**

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) 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 – an area within the WCSB approximately 250 km west of Edmonton, Alberta (the "**Alberta Deep Basin**") and areas within the WCSB extending from Grande Prairie, Alberta to approximately 100 km northwest of Fort St. John, NEBC ("**NEBC Montney**" and "**Peace River High Regional Charlie Lake**").

Alberta Deep Basin Core Area

The Alberta Deep Basin core area is a multi-objective tight natural gas sand play area with up to 15 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. The majority of the

Company's working interest lands have already received approval for down-spacing at four vertical wells per section. These two factors allow the Company to consistently deliver a significant portion of the highest productivity gas wells in the province on an annual basis.

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, 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 6,252 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 2017 capital exploration and development program, with approximately 125 gross horizontal wells currently planned. As developed, future wells will utilize the natural gas infrastructure that has been, and continues to be, constructed. In addition, the Company has 2,819 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 thirteen natural gas plants in the Alberta Deep Basin, ten of which, the Wild River 14-20, the Hinton 6-32, the Minehead 15-12, the Anderson 1-9, the Musreau 8-13, the Edson 4-17, the Ansell 1-34, the Brazeau 15-36, the Oldman 10-24 and the Sundance 15-7 are 100% owned and operated by Tourmaline. In aggregate, Tourmaline has in excess of 1 Bcf/d of natural gas processing capability within this plant network with plans to add an additional 50 MMcf/d at Wild River in the second quarter of 2017. Tourmaline's goal is to be one of the lowest-cost, most efficient operators in the Alberta Deep Basin, and during the next 12 to 18 months, the Company plans to optimize and systematically continue to further reduce costs of operating the Alberta Deep Basin assets.

In the Alberta Deep Basin, Tourmaline, since inception, has drilled approximately 540 gross natural gas wells and will drill an additional 125 gross wells in 2017. Tourmaline is one of the largest producers in the Alberta Deep Basin with production currently estimated at approximately 160,000 Boe/d, with further production growth anticipated through the balance of the year. The Company’s land holdings in the core area are approximately 3,000 gross sections. Year-end 2016 proved plus probable reserves were 872 MMboe in the Alberta Deep Basin, with approximately 719 gross (642.5 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 has concentrated its exploration and production program.

The Company has assembled its large Montney position primarily through multiple acquisitions completed between 2009 and 2016. 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. In NEBC, Tourmaline has an inventory of approximately 4,046 gross horizontal Montney development drilling locations, making the Company one of the largest participants in this resource play. To date, Tourmaline has drilled approximately 200 Montney multi-stage fracture-stimulated horizontal natural gas wells in NEBC with an additional approximately 75 gross Montney horizontal wells planned for 2017 in NEBC. Tourmaline is currently finalizing the 2017 – 2019 development plan for the Gundy CK Montney asset.

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 in 2017/2018, the timing of which is dependent on a natural gas price recovery. Tourmaline owns and operates four significant natural gas processing facilities with aggregate capacity of 275 MMcf/d with related gas gathering systems and NGL handling infrastructure. The Company is also planning a new 50 MMcf/d facility at Doe in the first half of 2017 to efficiently process the liquids-rich natural gas produced as a result of the ongoing Montney/Turbidite development. Current production in the NEBC Montney complex is approximately 305 MMcf/d of natural gas with 4,500 bbls per day of associated natural gas liquids. Tourmaline holds approximately 380 gross sections of Montney rights in the core area with 766 MMboe of proved plus probable reserves evaluated by the independent engineers at December 31, 2016 including approximately 748 gross (695.9 net) future drilling locations recognized in the Consolidated Reserve Report.

Peace River High Regional Charlie Lake

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, Alberta. The majority of the production in the complex is derived from oil and natural gas-charged reservoirs of the Triassic Charlie Lake formation. This area, currently producing approximately 20,000 Boe/d net to Tourmaline, has a large inventory of vertical and horizontal development drilling prospects in the Charlie Lake formation as well as attractive plays in several other formations. The Company has drilled a total of approximately 170 horizontal Charlie Lake oil wells to date and plans an additional approximately 75 gross horizontals through 2017. The Company controls an inventory of 1,596 future Upper Charlie Lake horizontals and is also delineating new discoveries in the Lower Charlie Lake and Triassic Montney formations.

Proved plus probable reserves in the area at December 31, 2016 are estimated to be 109 MMboe including approximately 352 gross (256.6 net) future drilling locations recognized in the Consolidated Reserve Report. The Company currently owns and operates two significant oil batteries capable of handling 48,000 bpd of fluids and the associated natural gas is delivered to a third party for processing. Tourmaline also has a 100% owned and operated 30 MMcf/d sour gas processing facility which came on-stream in 2014. An expansion to this facility, planned for 2017, will bring total capacity to up to 60 MMcf/d.

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 February 10, 2017 and effective as at December 31, 2016.

Disclosure of Reserves Data

The reserves data set forth below is based upon the report of GLJ Petroleum Consultants Ltd. ("**GLJ**") dated effective December 31, 2016, with an execution date of February 7, 2017 (the "**GLJ Reserve Report**") and the report of Deloitte LLP ("**Deloitte**") dated effective December 31, 2016, with an execution date of January 31, 2017 (the "**Deloitte Reserve Report**"), which are contained in the consolidated report of GLJ dated effective December 31, 2016, with a preparation date of February 10, 2017 (the "**Consolidated Reserve Report**"). The Consolidated Reserve Report evaluates, as at December 31, 2016, the crude oil, NGL and natural gas reserves of Tourmaline, and its current consolidated subsidiary Exshaw Oil Corp. ("**Exshaw**").

GLJ evaluated in the GLJ Reserve Report approximately 86.6% of the assigned total proved plus probable reserves and 83.9% of the total proved plus probable future net revenue discounted at 10%. Deloitte evaluated in the Deloitte Reserve Report approximately 13.4% of the assigned total proved plus probable reserves and 16.1% of the total proved plus probable future net revenue discounted at 10%. Deloitte evaluated in the Deloitte Reserve Report the Company's greater Hinton and Alberta Foothills properties located in the Alberta Deep Basin, the Company's Mulligan property located in the Alberta portion of the Peace River High and Exshaw's properties, also located in the Alberta portion of the Peace River High. Deloitte incorporated the forecast price and cost assumptions as described below under the heading "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 average of the January 1, 2017 price forecasts for GLJ, Sproule Associates Ltd. and McDaniel & Associates Consultants Ltd.

In accordance with NI 51-101, the Consolidated Reserve Report and the Deloitte Reserve Report include 100% of the reserves and future net revenue attributable to Exshaw's properties, without reduction to reflect the 9.4% third-party minority interest in Exshaw. Approximately 0.31% of the assigned total proved plus probable reserves and 0.53% of the total proved plus probable future net revenue discounted at 10% in the Consolidated Reserve Report is attributable to the 9.4% third-party minority interest in Exshaw.

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 currently 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. Prior to the Company’s consolidated report of GLJ dated effective December 31, 2015, with a preparation date of February 18, 2016 (the "**2015 Consolidated Reserve Report**"), Montney gas had been classified as product type "natural gas".

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 C 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, 2016
Forecast Prices and Costs(1)

	Light & Medium Crude Oil		Conventional Natural Gas		Shale Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	**Company Gross (Mbbls)**	**Company Net (Mbbls)**	**Company Gross (MMcf)**	**Company Net (MMcf)**	**Company Gross (MMcf)**	**Company Net (MMcf)**	**Company Gross (Mbbls)**	**Company Net (Mbbls)**	**Company Gross (Mboe)**	**Company Net (Mboe)**
Proved Developed Producing................	8,271	6,847	1,333,542	1,229,132	505,572	471,239	37,141	30,667	351,931	320,920
Proved Developed Non-Producing.........	425	364	71,567	65,260	73,281	69,321	3,414	2,926	27,981	25,720
Proved Undeveloped.............................	18,213	15,244	1,560,004	1,444,218	852,666	789,754	58,695	52,564	479,020	440,136
Total Proved..	26,910	22,455	2,965,113	2,738,610	1,431,519	1,330,315	99,250	86,167	858,932	786,777
Total Probable	27,453	22,652	2,004,129	1,802,306	2,529,840	2,247,300	104,777	89,140	887,891	786,727
Total Proved Plus Probable....................	54,362	45,109	4,969,243	4,540,916	3,961,358	3,577,615	204,027	175,307	1,746,822	1,573,504

	Net Present Values of Future Net Revenue ($000s)											
	Before Income Taxes Discounted at (%/year)					**After Income Taxes Discounted at (2) (%/year)**					**Unit Value Before Income Tax Discounted at 10%/year**	
Reserves Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	**($/Boe)**	**($/Mcfe)**
Proved Developed Producing	6,007,635	4,785,453	3,962,143	3,398,090	2,993,090	6,007,635	4,785,453	3,962,143	3,398,090	2,993,090	12.35	2.06
Proved Developed Non-Producing	537,122	404,308	323,230	269,716	232,093	537,122	404,308	323,230	269,716	232,093	12.57	2.09
Proved Undeveloped	7,030,367	4,626,831	3,248,018	2,386,932	1,811,983	5,203,885	3,452,904	2,436,399	1,794,495	1,361,532	7.38	1.23
Total Proved	13,575,124	9,816,592	7,533,390	6,054,737	5,037,165	11,748,642	8,642,665	6,721,772	5,462,301	4,586,715	9.57	1.60
Total Probable..................................	16,506,314	8,619,703	5,172,017	3,411,853	2,403,437	12,142,663	6,262,189	3,695,293	2,393,053	1,654,009	6.57	1.10
Total Proved Plus Probable	30,081,438	18,436,295	12,705,407	9,466,590	7,440,602	23,891,305	14,904,855	10,417,064	7,855,354	6,240,724	8.07	1.35

Notes:

(1) Numbers may not add due to rounding.
(2) 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 level of the Company which may be significantly different. The Company's financial statements and the management's discussion and analysis should be consulted for information at the level of the Company.

Total Future Net Revenue ($000s)
(Undiscounted)
as of December 31, 2016
Forecast Prices and Costs(1)

Reserves Category	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Tax Expenses	Income Tax Expenses	Future Net Revenue After Income Tax Expenses(2)
Proved Developed Producing.........	9,959,761	919,608	2,842,234	-	190,284	6,007,635	-	6,007,635
Proved Developed Non-Producing	802,207	72,607	142,404	40,781	9,293	537,122	-	537,122
Proved Undeveloped……………..	13,965,981	1,218,611	2,649,199	2,947,285	120,520	7,030,367	1,826,481	5,203,885
Total Proved……………………...	24,727,950	2,210,825	5,633,837	2,988,066	320,097	13,575,124	1,826,481	11,748,642
Total Probable……………………	31,464,890	3,805,153	7,492,904	3,429,046	231,473	16,506,314	4,363,651	12,142,663
Total Proved Plus Probable………	56,192,840	6,015,978	13,126,742	6,417,111	551,571	30,081,438	6,190,132	23,891,305

Notes:

(1) Numbers may not add due to rounding.
(2) 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 level of the Company, which may be significantly different. The Company's financial statements and the management's discussion and analysis should be consulted for information at the level of the Company.

Future Net Revenue
by Production Type
as of December 31, 2016
Forecast Prices and Costs

Reserves Category	Production Type(1)	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)	Unit Value (discounted at 10%/year) ($/Boe)	Unit Value (discounted at 10%/year) ($/Mcfe)
Proved Reserves	Light and Medium Crude Oil	709,277	14.85	2.47
	Conventional Natural Gas	4,327,830	8.92	1.49
	Shale Natural Gas	2,495,994	9.84	1.64
	Total	**7,533,101**	**9.57**	**1.60**
Proved Plus Probable	Light and Medium Crude Oil	1,156,746	12.17	2.03
	Conventional Natural Gas	6,377,828	8.03	1.34
	Shale Natural Gas	5,170,465	7.56	1.26
	Total	**12,705,040**	**8.07**	**1.35**

Note:

(1) By-products, including solution gas, natural gas liquids and other associated by-products are included in their main product group (natural gas or oil).

Reconciliation of Changes in Reserves

Reconciliation of Company Gross Reserves
by Principal Product Type
Forecast Prices and Costs

	Light and Medium Crude Oil			Conventional Natural Gas		
Factors	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**
December 31, 2015	21,037	21,270	42,306	2,197,624	1,557,770	3,755,394
Discoveries	-	-	-	1,668	411	2,079
Extensions and Improved Recovery	7,621	5,864	13,485	473,351	74,471	547,822
Technical Revisions	88	320	409	79,683	(4,640)	75,043
Acquisitions	5	1	6	487,008	386,838	873,847
Dispositions	-	-	-	(1,704)	(9,787)	(11,491)
Economic Factors	(1)	(2)	(3)	(4,139)	(931)	(5,070)
Production	(1,840)	-	(1,840)	(268,392)	-	(268,392)
December 31, 2016	**26,910**	**27,452**	**54,362**	**2,965,113**	**2,004,130**	**4,969,243**

	Shale Natural Gas			Total Natural Gas Liquids		
Factors	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**
December 31, 2015	1,132,100	806,566	1,938,666	68,068	48,894	116,962
Discoveries	-	-	-	19	5	23
Extensions and Improved Recovery	93,855	91,006	184,861	14,044	4,029	18,074
Technical Revisions	16,440	(9,340)	7,100	(402)	(3,034)	(3,435)
Acquisitions	277,567	1,641,613	1,919,180	24,371	55,117	79,488
Dispositions	-	-	-	(16)	(206)	(222)
Economic Factors	(598)	(6)	(604)	(103)	(28)	(131)
Production	(87,845)	-	(87,845)	(6,732)	-	(6,732)
December 31, 2016	**1,431,519**	**2,529,840**	**3,961,358**	**99,250**	**104,777**	**204,027**

	Total BOE		
Factors	**Gross Proved (Mboe)**	**Gross Probable (Mboe)**	**Gross Proved Plus Probable (Mboe)**
December 31, 2015	644,059	464,219	1,108,279
Discoveries	297	73	370
Extensions and Improved Recovery	116,200	37,473	153,673
Technical Revisions	15,707	(5,043)	10,664
Acquisitions	151,805	393,193	544,998
Dispositions	(300)	(1,837)	(2,137)
Economic Factors	(894)	(186)	(1,080)
Production	(67,945)	-	(67,945)
December 31, 2016	**858,932**	**887,891**	**1,746,822**

Notes to Reserves Data Tables:

(1) Numbers may not add due to rounding.
(2) Tourmaline has no bitumen, coalbed methane, gas hydrates, heavy crude oil, synthetic crude oil, synthetic gas or tight oil reserves.
(3) Company gross reserves do not include royalty interests received by Tourmaline.

(4) The crude oil, natural gas liquids, conventional natural gas and shale natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

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 at the individual entity level for all wells that were assigned reserves. Complete abandonment, disconnect and surface reclamation costs have not been estimated for suspended wells, gathering systems, batteries, plants or 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: Constant 2017 $ $US/Bbl	NYMEX WTI: Then Current $US/ Bbl	Brent Blend Crude Oil FOB North Sea Then Current $US/Bbl	Light, Sweet 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): Spec Ethane $Cdn/Btu	Edmonton Propane $Cdn/Bbl	Edmonton Butane $Cdn/Bbl	Edmonton Pentanes Plus Stream Quality $Cdn/Bbl
2017	0.7	0.7600	55.00	55.00	56.00	68.24	54.06	53.38	47.24	66.98	62.76	11.16	24.82	47.01	70.95
2018	2.0	0.7900	59.71	60.90	61.90	73.16	59.67	58.95	52.51	71.86	68.03	10.26	26.16	52.53	75.40
2019	2.0	0.8167	62.93	65.47	66.47	76.25	63.48	62.70	56.16	74.91	70.90	10.61	27.70	54.57	78.72
2020	2.0	0.8333	65.14	69.13	70.50	79.37	66.27	65.48	58.75	77.99	73.81	11.90	29.10	57.49	81.52
2021	2.0	0.8500	67.63	73.21	74.58	82.56	69.22	68.39	61.45	81.12	76.77	12.58	30.61	60.83	84.77
2022	2.0	0.8500	68.10	75.19	76.56	84.85	71.34	70.49	63.43	83.38	78.91	12.96	31.80	62.55	87.17
2023	2.0	0.8500	68.54	77.19	78.56	87.15	73.45	72.58	65.48	85.65	81.05	13.41	33.01	64.24	89.44
2024	2.0	0.8500	68.97	79.23	80.60	89.50	75.62	74.73	67.47	87.96	83.24	13.82	34.26	66.00	91.86
2025	2.0	0.8500	69.37	81.28	82.68	91.89	77.82	76.88	69.43	90.31	85.45	14.07	35.54	67.74	94.67
2026	2.0	0.8500	69.78	83.39	84.98	94.01	80.00	79.08	71.65	92.40	87.42	14.40	36.73	69.31	96.73
2027	2.0	0.8500	69.75	85.03	86.65	95.85	81.57	80.64	73.03	94.22	89.15	14.72	37.82	70.69	98.66
2028	2.0	0.8500	69.75	86.73	88.37	97.78	83.24	82.25	74.53	96.12	90.93	15.04	38.59	72.10	100.62
2029	2.0	0.8500	69.77	88.48	90.19	99.74	84.91	83.89	76.01	98.04	92.76	15.29	39.36	73.56	102.65
2030	2.0	0.8500	69.77	90.26	91.99	101.76	86.62	85.61	77.55	100.03	94.66	15.61	40.14	75.03	104.73
2031	2.0	0.8500	69.77	92.06	93.82	103.78	88.34	87.29	79.07	102.01	96.51	15.94	40.97	76.53	106.81
2032+	2.0	0.8500	69.75	+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: Constant 2017 $ $US/ MMbtu	NYMEX Henry Hub: Then Current $US/MMbtu	Midwest Price @ Chicago Then Current $US/ MMbtu	AECO/NIT Spot Then Current $Cdn/ MMbtu	Alberta Plant Gate Spot: Constant 2017 $ $Cdn/ MMbtu	Alberta Plant Gate Spot: Then Current $Cdn/ MMbtu	Alberta Plant Gate: ARP $Cdn/ MMbtu	Alliance Transfer Pool Spot $Cdn/ MMbtu	Saskatchewan Plant Gate: SaskEnergy $Cdn/ MMbtu	Saskatchewan Plant Gate: Spot $Cdn/ MMbtu	Sumas Spot $US/ MMbtu	British Columbia: Westcoast Station 2 $Cdn/ MMbtu	British Columbia: Spot Plant Gate $Cdn/ MMbtu	Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gate $Cdn/LT
2017	3.50	3.50	3.55	3.43	3.20	3.20	3.20	3.43	3.30	3.33	3.02	3.00	2.84	85.27	62.22
2018	3.24	3.30	3.35	3.17	2.88	2.94	2.94	3.17	3.04	3.07	2.87	2.78	2.62	97.06	73.09
2019	3.29	3.42	3.47	3.26	2.91	3.03	3.03	3.26	3.13	3.16	3.01	2.94	2.78	99.85	72.47
2020	3.53	3.75	3.80	3.67	3.23	3.43	3.43	3.67	3.53	3.57	3.44	3.35	3.18	101.57	71.96
2021	3.66	3.96	4.01	3.86	3.34	3.62	3.62	3.86	3.72	3.76	3.71	3.54	3.37	103.31	71.55
2022	3.69	4.07	4.12	3.97	3.38	3.73	3.73	3.97	3.83	3.87	3.82	3.65	3.48	105.10	73.64
2023	3.73	4.20	4.25	4.11	3.42	3.86	3.86	4.11	3.96	4.00	3.95	3.76	3.59	106.92	75.78
2024	3.74	4.30	4.35	4.23	3.46	3.98	3.98	4.23	4.08	4.12	4.05	3.88	3.71	108.77	77.97
2025	3.73	4.37	4.42	4.31	3.46	4.05	4.05	4.31	4.15	4.20	4.12	3.96	3.79	110.66	80.19
2026	3.73	4.46	4.51	4.41	3.47	4.15	4.15	4.41	4.25	4.29	4.21	4.06	3.89	112.60	82.47
2027	3.73	4.55	4.60	4.51	3.48	4.24	4.24	4.51	4.34	4.39	4.31	4.16	3.98	113.78	83.53
2028	3.74	4.65	4.70	4.60	3.48	4.33	4.33	4.60	4.44	4.48	4.40	4.24	4.07	115.28	84.62
2029	3.73	4.73	4.78	4.68	3.48	4.41	4.41	4.68	4.51	4.57	4.47	4.32	4.14	116.80	85.72
2030	3.73	4.82	4.87	4.77	3.48	4.50	4.50	4.77	4.61	4.67	4.56	4.41	4.23	118.36	86.85
2031	3.73	4.92	4.97	4.87	3.48	4.59	4.59	4.87	4.70	4.76	4.66	4.51	4.32	119.95	88.00
2032+	3.73	+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	+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, 2016 and GLJ and McDaniel & Associates Consultants Ltd. as at January 1, 2017 (each of which is available on their respective websites at www.gljpc.com, www.sproule.com and www.mcdan.com).
(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, 2016, the Company received the following weighted average prices, including realized gains and losses on financial instruments, in respect of its production: natural gas – $2.51/Mcf; NGL – $15.69/bbl; and oil – $55.73/bbl. The overall weighted average price received by Tourmaline on an oil equivalent basis was $17.94/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). See "*Disclosure of Reserves Data*".

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, 2016, 2015 and 2014.

Proved Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Shale Natural Gas[2] (MMcf)		Natural Gas Liquids (Mbbl)		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
2014	6,602	12,533	408,287	1,379,014	–	–	9,813	30,142	84,463	272,510
2015	2,391	14,037	280,809	1,176,582	157,687	649,202	11,007	38,531	86,480	356,866
2016	4,008	18,213	302,424	1,560,005	246,626	852,666	22,429	58,695	117,945	479,020

Notes:

(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.
(2) Because of recent product type guidelines and definitions, contained in NI 51-101, the Company's Montney proved reserves are now classified as shale natural gas. Prior to the 2015 Consolidated Reserve Report, they were referred to as natural gas.

It is anticipated that most of the proved undeveloped locations will be drilled by December 31, 2020.

Probable Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Shale Natural Gas[2] (MMcf)		Natural Gas Liquids (Mbbl)		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
2014	8,282	15,902	574,473	1,587,330	–	–	14,772	36,783	118,799	315,740
2015	5,502	18,065	306,210	1,245,167	169,929	650,607	13,910	39,973	98,768	374,001
2016	6,360	23,512	280,444	1,563,218	1,771,656	2,332,599	58,156	91,650	406,532	764,465

Notes:

(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.
(2) Because of recent product type guidelines and definitions, contained in NI 51-101, the Company's Montney probable reserves are now classified as shale natural gas. Prior to the 2015 Consolidated Reserve Report, they were referred to as natural gas.

It is anticipated that most of the future development capital associated with the probable undeveloped reserves will be incurred by December 31, 2022.

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 not completely considered for purposes of calculating GLJ's estimate of future net revenue but they are considered in the Company's calculation of its abandonment and reclamation obligations. Refer to note 8 "*Decommissioning Obligations"* in the recently filed Consolidated Financial Statements of the Company as at and for the years ended December 31, 2016 and 2015 for further discussion on the Company's abandonment and reclamation obligations.

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

Forecast Prices and Costs (Total Proved plus Probable) ($000s)

Year	**Abandonment and Reclamation Costs (Undiscounted)**	**Abandonment and Reclamation Costs (Discounted at 10%)**
2017	-	-
2018	-	-
2019	-	-
Thereafter	551,571	34,767
Total	**551,571**	**34,767**

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):

	Undiscounted Forecast Prices and Costs	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2017	904,480	988,157
2018	873,347	1,096,703
2019	751,212	1,106,146
2020	301,446	958,392
2021	120,668	869,396
Thereafter	36,553	1,398,317
Total	**2,988,066**	**6,417,111**

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

Other Oil and Natural Gas Information

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).

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, 2016 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)	218	154.4	85	59	1,489	1,209.0	304	224
British Columbia(1)	1	0.2	1	0.4	283	252.6	85	69.1
Saskatchewan(1)	1	0.1	-	-	-	-	-	-
Total	**220**	**154.6**	**86**	**59.4**	**1,772**	**1,461.6**	**389**	**293.5**

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.
(3) Includes wells of Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

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, 2016, 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	741,932	552,097	1,442,245	1,195,609	2,184,177	1,747,706
British Columbia	110,010	87,899	293,082	231,668	403,092	319,567
Saskatchewan	970	37	73,760	65,930	74,730	65,967
Total[(1)]	**852,912**	**640,033**	**1,809,087**	**1,493,207**	**2,661,999**	**2,133,240**

Notes:

(1) Includes developed and undeveloped properties of Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).
(2) 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, 2016 and the maximum net area of unproved properties for which the Company expects the rights to explore, develop and exploit to expire during 2016. There are no material work commitments necessary to maintain these properties.

Unproved Properties as at December 31, 2016

	Gross Acres	Net Acres	Maximum Net Acres Expected to Expire During 2017
Alberta	1,347,257	1,083,650	169,838
British Columbia	88,075	69,580	33,737
Saskatchewan	73,598	65,931	98
Total	**1,508,930**	**1,219,161**	**203,673**

The expiring acreage is being evaluated and attempts will be made to maintain our rights on the acreage.

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 current reserve forecasts, will be able to realize the benefit of its non-capital losses and expects to remain non-taxable through at least 2020. Tourmaline has approximately $7.0 billion of tax pools available as at December 31, 2016, which can be used to offset taxable income in future years.

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, 2016:

	$000s
Exploration, drilling and completions	508,433
Development, equipping and tie-in	120,065
Property acquisitions[1]	1,225,545
Property dispositions	(48,000)
Facilities	93,844
Geological and geophysical	8,335
Other (including capitalized G&A)	25,067
Total[2] [3]	**1,933,289**

Notes:

(1) Property acquisitions are a result of approximately $1,182.0 million of acquired proved properties and approximately $43.5 million of acquired unproved properties.
(2) Excludes non-cash share consideration of $367.7 million paid to Shell Canada related to the November 2016 property acquisition.
(3) Includes capital expenditures related to Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

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, 2016:

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Natural Gas	3	2.8	136	126.6
Oil	4	3.0	32	22.2
Service	-	-	-	-
Dry	-	-	-	-
Total[1]	**7**	**5.8**	**168**	**148.8**

Note:

(1) Includes wells in which Exshaw participated (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

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, 2017 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 Crude Oil 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	5,849	641,182	230,153	17,785	168,857
Proved Developed Non-Producing	61	33,136	24,909	1,408	11,143
Proved Undeveloped	3,257	242,948	124,546	8,444	72,950
Total Proved	9,167	917,267	379,609	27,637	252,950
Total Probable	78	66,224	37,695	1,425	18,822
Total Proved Plus Probable	9,245	983,491	417,303	29,062	271,772

Notes:

(1) No one field accounted for 20% or more of Tourmaline's estimated 2017 total proved production in the Consolidated Reserve Report.
(2) Numbers may not add due to rounding.
(3) Includes Exshaw production (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

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			
	2016[5]			
	December 31	September 30	June 30	March 31
Average Daily Production[1]				
Light and Medium Crude Oil (Bbl/d)	13,880	11,826	12,564	13,545
Conventional Natural Gas (Mcf/d)	734,084	654,163	727,402	762,556
Shale Natural Gas (Mcf/d)	248,629	241,093	251,627	271,236
NGL (Bbl/d)	14,148	8,312	10,076	9,984
Combined (Boe/d)	191,814	169,347	185,812	195,828
Average Price Received				
Light and Medium Crude Oil ($/Bbl)	58.82	54.97	59.51	49.70
Conventional Natural Gas ($/Mcf)	3.13	2.88	2.00	2.26
Shale Natural Gas ($/Mcf)	3.41	2.59	1.50	2.03
NGL ($/Bbl)	18.40	18.66	13.29	11.75
Combined ($/Boe)	22.01	19.54	14.61	15.66
Royalties Paid				
Light and Medium Crude Oil ($/Bbl)	6.80	5.69	5.29	3.52
Conventional Natural Gas ($/Mcf)[2]	0.08	(0.05)	0.04	0.00
Shale Natural Gas ($/Mcf)	0.25	0.29	(0.03)	0.07
NGL ($/Bbl)	1.46	2.97	1.02	0.89
Combined ($/Boe)	1.23	0.77	0.51	0.37
Production Costs (includes transportation)				
Light and Medium Crude Oil ($/Bbl)	11.89	11.02	15.64	15.48
Conventional Natural Gas ($/Mcf)	0.91	0.98	0.71	0.77
Shale Natural Gas ($/Mcf)	1.12	1.07	1.21	1.10
NGL ($/Bbl)[3]	-	-	-	-
Combined ($/Boe)	5.78	6.08	5.47	5.59
Netback Received ($/Boe)[4]	15.00	12.69	8.63	9.71

Notes:

(1) Before deduction of royalties.

(2) Includes royalty reductions for the quarters ended December 31, September 30, June 30 and March 31 of $0.12/Mcf, $0.13/Mcf, $0.08/Mcf and $0.12/Mcf, respectively, relating to the entire Alberta Gas Cost Allowance credits received by the Company.
(3) NGL volumes are derived from natural gas production, as such all the related operating costs are attributed to the production of natural gas.
(4) Netbacks are calculated by subtracting royalties and production costs from revenues.
(5) Includes Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

The following table sets forth the average daily production volumes for the year ended December 31, 2016 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	4,226	7,738	687,217	-	126,500
Other Alberta properties	5,733	328	32,195	-	11,427
British Columbia properties	2,994	2,567	-	253,101	47,745
Total[(1)]	**12,953**	**10,633**	**719,412**	**253,101**	**185,672**

Note:

(1) Includes Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).

The Company's production for the year ended December 31, 2016 was 7% light and medium crude oil, 6% NGLs, 64% conventional natural gas and 23% shale natural gas.

For the year ended December 31, 2016, approximately 27% of the Company's gross revenue was derived from crude oil production (including natural gas liquids), 55% was derived from conventional natural gas production and 18% was derived from shale natural gas production.

Forward Contracts and Marketing

The Company's commodity hedging policy has been established with the Board of Directors authorizing management to hedge up to 50% of current production. Other than as disclosed in the Company's Consolidated Financial Statements for the years ended December 31, 2016 and 2015, 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 5(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, 2016 and 2015 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 one of the largest natural gas producers in Canada, Tourmaline, which currently produces between 1.2 and 1.3 bcf/d, controls an estimated 9 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, many 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*".

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*".

Employees

At December 31, 2016, Tourmaline had 153 full time employees and 9 consultants located at its Calgary office, and 41 full time employees and 160 contract operators in various field locations. Tourmaline currently has 163 full time employees and 9 consultants located at its Calgary office, and 43 full time employees and 160 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 completed during the current financial year. No material reorganization is currently proposed 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

Tourmaline has never declared or paid any cash dividends on the Common Shares. Tourmaline currently intends to retain future earnings, if any, for future operations, expansion and debt repayment. Any decision to declare and pay dividends will be made at the discretion of the Board of Directors and will depend on, among other things, Tourmaline's results of operations, current and anticipated cash requirements and surplus, financial condition, contractual restrictions and financing agreement covenants, solvency tests imposed by corporate law and other factors that the Board may deem relevant.

In addition to the foregoing, Tourmaline's ability to pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness that Tourmaline has incurred or may incur in the future including the terms of Tourmaline's credit facilities. In certain circumstances, Tourmaline's credit facility may prohibit Tourmaline from declaring or paying any dividends (excluding stock dividends) to any of its shareholders or returning any capital (including by way of dividend) to any of its shareholders.

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 of Directors 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 of Directors 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 of Directors, 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 of Directors 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 of Directors 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

Tourmaline has not asked for and received a stability rating, or to the knowledge of Tourmaline, has received any other kind of rating, including, a provisional rating, from one or more approved rating organizations for securities of Tourmaline that are outstanding and which continue in effect.

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		
	High ($/share)	Low ($/share)	Trading Volume
2016			
January	28.73	21.14	19,898,076
February	28.04	24.12	17,409,029
March	30.22	24.97	19,581,599
April	29.87	24.62	15,803,496
May	32.10	26.88	16,496,916
June	34.57	30.03	14,166,112
July	34.79	32.09	7,785,442
August	37.48	32.05	12,262,422
September	37.90	33.67	11,700,399
October	39.77	34.68	13,915,051
November	37.85	33.24	16,741,923
December	39.06	35.35	18,460,708

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 2016

Date of Issuance	Number of Options	Exercise Price of Options
January 15, 2016	20,000	$22.49
March 15, 2016	105,000	$29.26
April 15, 2016	15,300	$26.85
May 15, 2016	65,000	$30.24
July 15, 2016	45,000	$33.88
September 15, 2016	370,000	$36.50
October 15, 2016	110,000	$36.31
November 15, 2016	2,577,700	$34.29
December 15, 2016	105,000	$36.99

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the Company's knowledge, as of December 31, 2016, 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 executive 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
Jill T. Angevine(1)(3)(5) Alberta, Canada	Director	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)(5) 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) 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
Robert W. Blakely(1)(2)(3)(5)(6) Ontario, Canada	Director	President of Likrilyn Capital Corporation, an investment management company.	October 27, 2008
John W. Elick(5) Alberta, Canada	Director	Chairman of Cinch Energy Corp. from November 2001 to July 12, 2011 and Chief Executive Officer of Cinch Energy Corp. from November 2001 to November 2009.	March 19, 2013
Kevin J. Keenan(4)(5) Alberta, Canada	Director	Independent businessman since November 2009. Prior thereto, Vice President, Operations and Chief Operating Officer of Exshaw. Prior thereto, President of Manor House Venture Partners Inc.	October 27, 2008
Phillip A. Lamoreaux(1)(2)(3)(4)(5) California, United States	Director	Mr. Lamoreaux was the managing general partner and portfolio manager of Lamoreaux Partners, an investment management company, before retiring in December 2015.	September 9, 2010
Andrew B. MacDonald(1)(2)(3)(5) 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
Ron Wigham(5) Alberta, Canada	Director	Independent Businessman since January 2014, prior thereto Vice Chairman, Peters & Co. Limited	March 7, 2016
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
Ronald J. Hill Alberta, Canada	Vice President, Exploration	Vice President, Exploration of Tourmaline since November 2009. Prior thereto, Senior Geologist at Tourmaline and Duvernay.	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

Name, Province or State and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since
Allan J. Bush Alberta, Canada	Vice President, Operations and Chief Operating Officer	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
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, Drilling and Completions Operations	Vice President, Drilling and Completions Operations of Tourmaline since May 2015. Prior thereto, Completions Manager of Tourmaline.	N/A

Notes:

(1) Member of the Audit Committee. Mr. Blakely is the Chairman of the Audit Committee.
(2) Member of the Compensation Committee. Mr. Blakely is the Chairman of the Compensation Committee.
(3) Member of the Corporate Governance and Nominating Committee. Mr. MacDonald is the Chairman of the Corporate Governance and Nominating Committee.
(4) Member of the Reserves, Safety and Environmental Committee. Mr. Keenan is the Chairman of the Reserves, Safety and Environmental Committee.
(5) Independent director.
(6) 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 obligations to the Company. The Company's officers are appointed by and serve at the discretion of the Board of Directors.

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, 19,843,682 Common Shares or approximately 7.4% 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. Keenan, a director of Tourmaline, served as a director of Detector Exploration Ltd. ("**Detector**"), a public Company listed on the TSX Venture Exchange, until March 17, 2016. On February 22, 2016, a secured creditor of Detector was granted an order under the *Bankruptcy and Insolvency Act (Canada)* appointing a receiver to take possession and exercise control over all of Detector's current and future assets.

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.

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; and

(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; and (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 Canadian Stock Transfer Company, Inc. 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 natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas, including the governments of Canada, Alberta, British Columbia, Saskatchewan, and Manitoba, all of which investors in the oil and gas industry should carefully consider. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments governments may enact in the future. The following comprises some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

In Canada, producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, regional market and transportation issues also influence prices. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB underwent a consultation process to update the regulations governing the issuance of export licences. The updating process was necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act (Canada)* (the "***Prosperity Act***") which received Royal Assent on June 29, 2012. The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provides the requirements for obtaining long-term licences.

Natural Gas

Canada's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3 per day) must be made pursuant to an NEB order. Natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

The Canadian federal government has signaled that it will *inter alia* phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing stringent reviews for pipelines and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

In Alberta, the Crown owns 81% of the province's mineral rights. The remaining 19% are 'freehold' mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial government royalty rates apply to Crown-owned mineral rights. On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF formally took effect on January 1, 2017 for wells drilled after this date. Wells drilled prior to January 1, 2017 will continue to be governed by the "New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) (the "**Alberta Royalty Framework**") for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout; (ii) Mid-Life; and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on total depth, length, and proppant placed). The new royalty rate for Pre-Payout under the MRF will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase of the MRF, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently the equivalent of 194 m^3 (40 barrels of oil equivalent per day or 345,500 m^3 of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, that came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the Alberta Energy Regulator ("**AER**").

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the Government of Alberta plans to increase transparency in the method and figures by which the royalties are calculated. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to the Alberta Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36% and a minimum royalty rate of 5%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from lands where the Crown does not hold the rights to mines and minerals and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from freehold mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). These initiatives apply to wells drilled before January 1, 2017, for a ten-year period, until January 1, 2027. Specifically:

Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery ("**EOR**") scheme. The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit-selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low-productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well, and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the applicable freehold production tax is based on the volume of monthly production, and 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 the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale depending on the total number of hectares owned by the entity.

As of January 1, 2017, all liquid natural gas ("**LNG**") facilities are subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer's net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment, the Government of British Columbia will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

The Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs, including the following:

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met, is intended to reflect the higher drilling and completion costs. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". The pre-existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014. Currently all wells that qualify for the tier one royalty credits are subject to a minimum royalty of 6% while wells that qualify for the tier two royalty credits are subject to a minimum royalty of 3%. These minimum royalty amounts apply when the net royalty payable would otherwise be zero for a production month;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay if the re-entry well event is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3 year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 m^3;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 m^3 per metre of depth for exploratory wildcat wells and less than 11 m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 m^3. Horizontal wells that are spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

Saskatchewan

In Saskatchewan, the Crown owns approximately 70% of the oil and gas rights. For the Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by companies focused on oil and gas operations.

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is 3% of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations. In addition, a mineral rights tax is charged to owners of mineral rights paid on an annual basis at the rate of $1.50 per acre owned.

The amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into types, being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil, being "fourth tier oil", "third tier oil", "new oil" and "old oil", depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently:

Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as third tier oil or fourth tier oil).

Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002.

For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the Production Tax Factor ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for old oil, 10.0 for new oil and third tier oil and 12.5 for fourth tier oil. The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for old oil, new oil and third tier oil, and 250 m^3 per month for fourth tier oil. Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250,000 m^3 per month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per GJ for third and fourth tier gas and $0.95 per GJ for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.** The current regulatory scheme provides for certain differences with respect to the administration of fourth tier gas, which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the fourth tier royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the fourth tier royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of fourth tier oil Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the fourth tier royalty tax rate;

- Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002 whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on EOR projects pre-payout and 20% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting third tier oil royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards apply to existing licensed wells and facilities on July 1, 2015.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licences and applications in the oil and gas sector by eliminating 11 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. Effective October 27, 2016, the Saskatchewan Ministry of the Economy streamlined a further 20 different service fees, and implemented a Crown Minerals Electronic Registry for oil and gas tenure in Saskatchewan that will provide for certainty of tenure comparable to Alberta and reduce the administrative burden.

Manitoba

In Manitoba, the Crown owns approximately 20% of the oil and gas rights in the province, with the remainder being freehold lands. The royalty amount payable on oil produced from Crown lands depends on the classification of the oil produced as "old oil" (produced from a well drilled prior to April 1, 1974 that does not qualify as new oil or third tier oil), "new oil" (oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974 and prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well), "third tier oil" (oil produced from a vertical well drilled after April 1, 1999, an abandoned well re-entered after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date), or "holiday oil" (oil that is exempt from any royalty or tax payable). Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold, calculated for each production month.

Producers of oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale based on the monthly production volume and the classification of oil as old oil, new oil, third tier oil and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated for each production month. There is no freehold production tax payable on gas consumed as lease fuel.

The Government of Manitoba maintains a Drilling Incentive Program (the "**Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no Crown royalties or freehold production taxes are payable until the holiday oil volume has been produced. Holiday oil volumes must be produced within 10 years of the finished drilling date or the completion date of a major workover.

Wells drilled or receiving a marginal well major workover incentive after December 31, 2013 and prior to January 1, 2019 must pay a minimum royalty of 3% on Crown production or a minimum tax of 1% on freehold production. Wells receiving the *Pressure Maintenance Project Incentive* (outlined below) are not subject to the minimum royalty or minimum tax.

Wells drilled for injection, or converted to injection wells, in an approved enhanced recovery project, earn a one-year holiday for portions of the project area.

The Program consists of the following components, such components being subject to additional considerations under the *Crown Royalty and Incentives Regulation*:

- *Vertical Well Incentive* provides licensees of a vertical development or exploratory well drilled after December 31, 2013 and prior to January 1, 2019 with a holiday oil volume (a "**HOV**") of 500 m^3. To qualify, the well must be less than 1.6 kilometres from the nearest well cased for production from the same or deeper zone;

- *Exploration and Deep Well Incentive* provides a HOV for exploratory or deep oil development wells drilled after December 31, 2013 and prior to January 1, 2019 as follows:

- Non-deep exploratory wells drilled more than 1.6 kilometres from the nearest well cased for production from the same or deeper zone earn a HOV of 4,000 m^3;

- Deep exploratory wells drilled below the Birdbear formation earn a HOV of 8,000 m^3; and

- Deep development wells completed for production in the Birdbear formation or deeper earn a HOV of 8,000 m^3;

- *Horizontal Well Incentive* provides a HOV of 8,000 m^3 for any horizontal well drilled after December 31, 2013 and prior to January 1, 2019 achieving an angle of at least 80 degrees for a minimum distance of 100 metres;

- *Marginal Well Major Workover Incentive* provides a HOV of 500 m^3 for any marginal well where a major workover is completed prior to January 1, 2019. A marginal oil well is a well or abandoned well that was not operated over the previous 12 months or that produced at an average rate of less than 3 m^3 per operating day;

- *Pressure Maintenance Project Incentive* provides a one-year exemption from the payment of Crown royalties or freehold production taxes for the unit tract in which an injection well is drilled or a well is converted to water injection. This exemption applies to the unit tract in which the vertical injection well is located and for a horizontal injection well to a maximum of four unit tracts within the drainage unit of the well. For a well that is converted to injection after December 31, 2013 and before January 21, 2019 and that has a remaining HOV, the exemption will be extended to 18 months; and

- *Solution Gas Conservation Incentive* provides a royalty and tax exemption on gas until December 31, 2018 for projects after December 31, 2013 that capture solution gas.

The Holiday Oil Volume Account, which allowed the movement of HOV to and from wells under specific conditions, was eliminated January 1, 2015. Previously, the holder of an existing account was able to make a one-time transfer of 2,000 m^3 to a well drilled between January 1, 2014 and December 31, 2014.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces, with the exception of Manitoba where private ownership accounts for approximately 80% of the crude oil and natural gas rights in the southwestern portion of the province. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia, Saskatchewan, and Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. The Government of British Columbia expanded its policy of deep rights reversion for leases issued after March 29, 2007 to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of the primary term.

Alberta also 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 all leases and licences issued after January 1, 2009 at the conclusion of the primary term of the lease or licence.

Production and Operation Regulations

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

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which is subject to governmental review and revision from time to time. Such legislation provides 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 and facility sites. Compliance with such legislation 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 to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environmental assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

On June 20, 2016, the Federal Government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An Expert Panel has been convened and is expected to complete its work by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the Panel's report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the Federal Government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The Federal Government has not provided any indication on what changes—if any—will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

In a further development, on November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast. It is unclear how the proposed moratorium may affect ongoing LNG export projects currently under consideration and development. On the same day, the Government of Canada also approved, subject to a number of conditions, the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as the replacement of Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline have been satisfied. Additionally, the new administration in the United States has indicated a willingness to revisit other pipeline projects that had been previously rejected.

Alberta

The AER is the single regulator responsible for all energy development in Alberta. The AER ensures 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 Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("**IRMS**"). The IRMS method 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, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF 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.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licences, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

Phase 1 Consultation of the North Saskatchewan Region Plan ("**NSRP**") has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The NSRP is located in central Alberta and is approximately 85,780 square kilometres in size and affects activities in central Alberta, and encompasses an area between the province's borders with British Columbia and Saskatchewan. The Upper Peace Region Plan, Lower Peace Region Plan, Red Dear Region Plan and Upper Athabasca Region Plan have not been started.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "***OGAA***") impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. Under the *OGAA*, the British Columbia Oil and Gas Commission (the "**Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The *OGAA* requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the *OGAA*, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Saskatchewan

In May 2011, the Government of Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("***SKOGCA***"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* ("***OGCR***") and *The Petroleum Registry and Electronic Documents Regulations* ("***Registry Regulations***"). The aim of the amendments to the *SKOGCA*, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the *Registry Regulations* and the *OGCR*, the Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Manitoba

In Manitoba, the Petroleum Branch of Innovation, Energy and Mines develops, recommends, implements and administers policies and legislation aimed at the sustainable, orderly, safe and efficient development of crude oil and natural gas resources. Oil and gas exploration, development, production and transportation are subject to regulation under *The Oil and Gas Act* ("***MBOGA***"), *The Oil and Gas Production Tax Act* and related regulations and guidelines.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act ("OGCA")* establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct or is unable to meet its obligations. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "**Changes**") that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed assets to deemed liabilities under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("***Bulletin 16***") in an urgent response to a decision from the Alberta Court of Queen's Bench, which is currently under appeal with the Court of Appeal of Alberta. In *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("***Redwater***"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA and the *Bankruptcy and Insolvency Act* ("***BIA"***), and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the *BIA*. *Bulletin 16* provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

1. The AER will consider and process all applications for licence eligibility under Directive 067: Applying for Approval to Hold EUB Licences as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licencee eligibility approval if appropriate in the circumstances.
2. For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.

3. As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

In order to clarify and revise the interim rules in *Bulletin 16*, the AER issued *Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("***Bulletin 21***") on July 8, 2016 and reaffirmed its position that an LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, *Bulletin 21* did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if:

1. The licensee already has an LMR of 2.0 or higher;

2. The acquisition will improve the licensee's LMR to 2.0 or higher; or

3. The licensee is able to satisfy its obligations, notwithstanding an LMR below 2.0, by other means.

The AER provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee's LMR not meeting the interim requirement. The Alberta Court of Appeal heard the appeal of the *Redwater* decision on October 11, 2016, with the Court reserving its decision.

The AER implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("***Directive 013***"). The IWCP applies to all inactive wells that are noncompliant with *Directive 013* as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of *Directive 013* within 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with *Directive 013* or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota.

British Columbia

In British Columbia, the Commission oversees the Liability Management Rating Program (the "**BC LMR Program**"), designed to manage public liability exposure related to oil and 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 Commission determines the required security deposits for permit holders under the *OGAA*. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the *OGAA*.

Saskatchewan

In Saskatchewan, the Ministry of the Economy administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the *SKOGCA*. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities. On August 19, 2016, the Ministry of the Economy released a notice to all operators that it would follow the AER's interim rules by processing all licence transfer applications as non-routine until further notice.

Manitoba

To date, the Government of Manitoba has not implemented a liability management rating program similar to those found in the other western provinces. However, operators of wells licensed in the province are required to post a performance deposit to ensure that the operation and abandonment of wells and the rehabilitation of sites occurs in accordance with the MBOGA and the *Drilling and Production Regulations*. In certain circumstances, a performance deposit may be refunded. The MBOGA also establishes the Abandonment Fund Reserve Account (the "**Abandonment Fund**"). The Abandonment Fund is a source of funds that may be used to operate or abandon a well when the licensee or permittee fails to comply with the MBOGA. The Abandonment Fund may also be used to rehabilitate the site of an abandoned well or facility or to address any adverse effect on property caused by a well or facility. Deposits into the Abandonment Fund are comprised of non-refundable levies charged when certain licences and permits are issued or transferred as well as annual levies for inactive wells and batteries.

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors.

As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, the GHG emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC. INDCs were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016 (the "**Paris Agreement**"). Among other items, the Paris Agreement constitutes the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The Government of Canada ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada's INDC became its Nationally Determined Contributions ("**NDC**"). As a result, the Government of Canada replaced its INDC of a 17% reduction target established in the Copenhagen Accord with an NDC of 30% reduction below 2005 levels by 2030.

On June 29, 2016, the North American Climate, Clean Energy and Environment Partnership was announced among Canada, Mexico and the United States, which announcement included an action plan for achieving a competitive, low-carbon and sustainable North American economy. The plan includes setting targets for clean power generation, committing to implement the Paris Agreement, setting out specific commitments to address certain short-lived climate pollutants, and the promotion of clean and efficient transportation.

Additionally, on December 9, 2016, the Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of $10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by $10 annually until it reaches $50 per tonne in 2022 at which time the program will be reviewed.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's operations and cash flow.

Alberta

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate* Change *and Emissions Management Act* (the "***CCEMA***") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the *Specified Gas Emitters Regulation* ("***SGER***"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHG emissions in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

On June 25, 2015, the Government of Alberta renewed the *SGER* for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. As of 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

A Regulated Emitter can meet its emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Contributions to the Fund are made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG emissions in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan. On June 7, 2016, the *Climate Leadership*

Implementation Act ("***CLIA***") was passed into law. The *CLIA* enacted the *Climate Leadership Act* ("***CLA***") introducing a carbon tax on all sources of GHG emissions, subject to certain exemptions. An initial economy-wide levy of $20 per tonne was implemented on January 1, 2017, increasing to $30 per tonne in January of 2018. All fuel consumption—including gasoline and natural gas—will be subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the *SGER* framework until the end of 2017 and are exempt from paying the carbon levy on fuels used in operations until this time. Upon the expiry of the *SGER*, the Government of Alberta intends to transition to a proposed *Carbon Competitiveness Regulation,* in which sector specific output-based carbon allocations will be used to ensure competitiveness. A 100 megatonne per year limit for GHG emissions was implemented for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit.

There are certain exemptions to the carbon levy imposed by the *CLA*. Until 2023, fuels consumed, flared or vented in a production process by conventional oil and gas producers will be exempt from the carbon levy. An exemption also applies for biofuels and fuels sold for export. In addition, marked fuels used in farming operations as well as personal and band uses by First Nations are exempt.

The passing of the *CLIA* is the first step towards executing the Climate Leadership Plan (other legislation is still pending). In addition to enacting the *CLA*, the *CLIA* also enacted the *Energy Efficiency Alberta Act,* which enables the creation of Energy Efficiency Alberta, a new Crown corporation to support and promote energy efficiency programs and services for homes and businesses.

The Government of Alberta also signaled its intention through its Climate Leadership Plan to implement regulations that would lower methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

British Columbia launched its Climate Action Plan in 2008 and met its first interim emission reduction targets in 2012. In February 2008, the Government of British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of GHG emissions. The final scheduled increase took effect on July 1, 2012, wherein the Government of British Columbia froze the tax level to allow other jurisdictions time to adopt comparable carbon pricing mechanisms. In order to make the tax revenue-neutral, the Government of British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

Further, on April 3, 2008, the Government of British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "***Cap and Trade Act***"), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of GHG emissions by 2020 and an 80% reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Alberta government, the *Cap and Trade Act* establishes an absolute cap on GHG emissions.

The *Greenhouse Gas Emission Reporting Regulation*, implemented under the authority of the *Cap and Trade Act*, set out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010.

Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. The reporting system for large emitters of GHGs has since been streamlined by the *Greenhouse Gas Industrial Reporting and Control Act* (the "***GGIRCA***") and its associated regulations that came into force on January 1, 2016. The *GGIRCA* sets out benchmarked performance standards for different industrial facilities and sectors, provides for emissions offsets through the purchase of emission credits or emission offsetting projects, among other measures, and replaces the *Cap and Trade Act*.

Following the 2012 Budget, the Government of British Columbia undertook a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review, the Government of British Columbia confirmed that it will keep its revenue-neutral carbon tax–the current carbon tax rates, tax base will be maintained, and revenues will continue to be returned through tax reductions.

On August 19, 2016, the Government of British Columbia unveiled its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 25 million tonnes below current forecasts by 2050, and reaffirmed that it will achieve its 2050 target of an 80% reduction in emissions from 2007 levels. In addition to various measures across the economy that are designed to incentivize the growth of the renewable energy sector, the use of low GHG emitting technologies, and the improvement of energy efficiency, among other goals, the Government of British Columbia will soon implement a formal policy to regulate carbon capture and storage projects. Further, the Climate Leadership Plan sets out a strategy to reduce methane emissions in the upstream natural gas sector, beginning with a Legacy phase that targets a 45% reduction in fugitive and vented emissions by 2025 for facilities built before January 1, 2015, followed by a Transition phase for facilities built between 2015 and 2018 that involves a new offset protocol and a Clean Infrastructure Royalty Credit Program along with other incentives, and finally a Future phase that will implement standards going forward.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "***MRGGA***") to regulate GHG emissions in the province. The *MRGGA* received Royal Assent on May 20, 2010 and will come into force on proclamation. The *MRGGA* establishes a framework for achieving the provincial target of a 20% reduction in GHG emissions from 2006 levels by 2020. Although the *MRGGA* and related regulations have yet to be proclaimed in force, draft versions indicate that the Government of Saskatchewan will permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to the federal climate change initiatives. It remains unclear whether the scheme implemented by the *MRGGA* will be based on emissions intensity or an absolute cap on emissions.

Manitoba

The Government of Manitoba commenced public consultations with respect to the development of a cap and trade system to reduce GHG emissions in 2010. The enactment of *The Climate Change and Emissions Reductions Act* (Manitoba) set emission reduction targets as of December 31, 2012 at 6% below 1990 emissions and details the commitment of the Government of Manitoba to various initiatives in an effort to reduce GHG emissions. On December 3, 2015, the Government of Manitoba announced Manitoba's Climate Change and Green Energy Action Plan to address climate change and create green jobs. One component of this plan involves cutting GHG emissions by one-third of its 2005 levels by 2030, in part by implementing a cap and trade program for large emitters. Following this announcement, on December 7, 2015, the Government of Manitoba announced that it has signed a memorandum of understanding with both Ontario and Quebec formalizing the intent of all three provinces to link their respective cap-and-trade systems. However, legislation has not yet been enacted to implement the initiatives outlined in Manitoba's Climate Change and Green Energy Action Plan or the memorandum of understanding.

RISK FACTORS

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

Exploration, Development and Production Risks

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

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

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, 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, the environment and personal injury. Particularly, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company.

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

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

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Company's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and may continue to restrict, the Company's cash flow resulting in a reduced capital expenditure budget. Consequently, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year over year basis.

Prices, Markets and Marketing

Numerous factors beyond the Company's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Company. The Company's ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Company's reserves are from pipelines, railway lines, processing and storage facilities; operational problems affecting pipelines, railway lines and facilities; and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Company.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Company's ability to access such markets. Oil prices are expected to remain volatile as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, OPEC's decisions pertaining to the oil production of OPEC member countries, and non-OPEC member countries' decisions on production levels, among other factors. A material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices.

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

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

See "*Weakness in the Oil and Gas Industry*".

Alternatives to and Changing Demand for Petroleum Products

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

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves 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 the 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 Company'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. Such variations could be material.

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

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

Substantial Capital Requirements

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

- the overall state of the capital markets;
- the Company's credit rating (if applicable);
- 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 Company's securities in particular.

Further, if the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The Company may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Company 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 Company 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 gas industry and/or global economic and political volatility, the Company may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

As a result of global economic and political volatility, the Company may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Company'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 Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Company's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Reliance on Key Personnel

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key personnel insurance in effect for the Company. The contributions of the existing management team to the immediate and near term operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and gas market. Similarly, the market price of the Common Shares of the Company could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares of the Company will trade cannot be accurately predicted.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Company.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. 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. 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 Company's ability to market its products internationally, increase costs for goods and services required for the Company's operations, reduce access to skilled labour and negatively impact the Company's business, operations, financial conditions and the market value of its Common Shares.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Company's costs, either of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Company will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that the Company 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 Company'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.

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Company's projects. An increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See "*Industry Conditions - Royalties and Incentives*".

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Management of Growth

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

Information Technology Systems and Cyber-Security

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

Further, the Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The Company applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations.

Operational Dependence

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

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

Project Risks

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;

- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Company could be unable to execute projects on time, on budget, or at all and may be unable to market the oil and natural gas that it produces effectively.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Company 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 Company 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 availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the Company's inability to realize the full economic potential of its production or in a reduction of the price offered for the Company's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. 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 Company's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, the Company's financial condition, operations and cash flows. In addition, the federal government has signaled that it plans to review the National Energy Board approval process for large federally regulated projects. This may cause the timeframe for project approvals to increase for current and future applications.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

A portion of the Company's production may, from time to time, be processed through facilities owned by third parties and over which the Company 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 materially adverse effect on the Company's ability to process its production and deliver the same for sale.

Competition

The petroleum industry is competitive in all of its phases. The Company competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas. The Company's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Company. 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 Company. The Company'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 petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company. There can be no assurance that the Company will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If the Company does implement such technologies, there is no assurance that the Company will do so successfully. One or more of the technologies currently utilized by the Company or implemented in the future may become obsolete. In such case, the Company's business, financial condition and results of operations could be affected adversely and materially. If the Company 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.

Hydraulic Fracturing

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 Company's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves.

Due to seismic activity reported in the Fox Creek area of Alberta, seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay Zone in the Fox Creek area were announced by the AER in February 2015. These requirements include, among others, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events, and the suspension of operations if a seismic event above a particular threshold occurs. The AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and 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.

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 Company to incur costs to remedy such discharge. Although the Company 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 Company's business, financial condition, results of operations and prospects.

Liability Management

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 obligation. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes to the required ratio of the Company's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Company's compliance requirement. In addition, the liability management system may prevent or interfere with the Company's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The recent Alberta Court of Queen's Bench decision, *Redwater Energy Company (Re)* 2016 ABQB 278, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent. The AER appealed this decision and issued interim rules to administer the liability management program and until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces. See "*Industry Conditions - Liability Management Rating Programs*".

Climate Change

The Company's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Company to comply with greenhouse gas ("**GHG**") emissions legislation at the provincial or federal level. 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. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**"**)** and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it would seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new GHG emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. In addition, on January 1, 2017 the *Climate Leadership* Act ("**CLA**") come into effect in the Province of Alberta introducing a carbon tax on almost all sources of GHG emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

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 may negatively affect the Company's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Company'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 Company receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Company's operations, which may have a negative impact on the Company's financial results**.**

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

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Common Shares of the Company.

Credit Facility Arrangements

The Company currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Company 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 Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with covenants could result in default under the Company's credit facility, which could result in the Company being required to repay amounts owing thereunder. The acceleration of the Company's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Company's credit facility may impose operating and financial restrictions on the Company that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Company'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.

If the Company's lenders require repayment of all or 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 Company would be in a position to make such repayment. Even if the Company is able to obtain new financing in order to make any required repayment under its credit facilities, it may not be on commercially reasonable terms or terms that are acceptable to the Company. If the Company is unable to repay amounts owing under credit facilities, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Issuance of Debt

From time to time, the Company 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 Company's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Company may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time, the Company 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 Company engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose 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;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Company 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 Company will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

Expiration of Licences and Leases

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

Diluent Supply

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 may cause its price to increase thereby increasing the cost to transport heavy oil and bitumen to market and correspondingly increasing the Company's overall operating cost, decreasing its net revenues and negatively impacting the overall profitability of its heavy oil and bitumen projects.

Insurance

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

Title to Assets

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

Geopolitical Risks

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

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

Dilution

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

Internal Controls

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

Litigation

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

Intellectual Property Litigation

Due to the rapid development of oil and gas technology, in the normal course of the Company's operations, the Company may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that the Company has infringed the intellectual property rights of others or commenced lawsuits against others who the Company believes are infringing upon its intellectual property rights. The Company'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 Company's favour. In the event of an adverse outcome as a defendant in any such litigation, the Company may, among other things, be required to: (a) pay substantial damages; 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 Company 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 Company's business and financial results.

Aboriginal Claims

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

Income Taxes

The Company 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 Company, 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 Company. Furthermore, tax authorities having jurisdiction over the Company may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's detriment.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Company's ability to access its properties and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Company.

Dividends

The Company has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Company, the need for funds to finance ongoing operations and other considerations, as the Board of Directors of the Company considers relevant.

Third Party Credit Risk

The Company 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 Company may be exposed to third party credit risk from operators of properties in which the Company has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company 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 Company being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's financial and operational results.

Reliance on Royalty Payers

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

In addition, due to the current low and volatile commodity prices, many companies, including companies that may have a working interest in the lands in which the Company has a royalty interest, may be in financial difficulty, which could affect their ability to fund and pursue capital expenditures on such lands. In addition, weak commodity prices might result in companies choosing to defer capital spending or shutting-in existing production. Any reduction in the drilling and production from lands in which the Company has a royalty interest will negatively affect the Company's cash flows and financial results.

Financial difficulty of companies who have lands in which the Company has a royalty interest may affect the Company'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.

Breach of Confidentiality

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

Conflicts of Interest

Certain directors or officers of the Company 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 of officer of a Company who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Company to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the *ABCA*. See "Directors and Officers – Conflicts of Interest".

Expansion into New Activities

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

Forward-Looking Information May Prove Inaccurate

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

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward-Looking Statements*" of this Annual Information Form.

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 "D".

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 Company's financial statements and the related management's discussion and analysis 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
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
km2	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).

To Convert From	To	Multiply By
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 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 2017.

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;
- aboriginal 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;
- restrictions contained in the Company's;
- 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.

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.

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 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 14,713 undrilled locations, 906 are proved undeveloped locations, 20 are proved non-producing locations, 893 are probable undeveloped locations, nil are probable non-producing and 12,894 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 certain 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"

GLJ PETROLEUM CONSULTANTS LTD.
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, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, 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 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, 2016, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $MM)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	December 31, 2016	Canada	-	$10,663	-	$10,663

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

7. We have no responsibility to update our 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 Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 7, 2017.

ORIGINALLY SIGNED BY

“Originally signed by”

Chad P. Lemke, P. Eng.
Manager, Engineering

SCHEDULE "B"

DELOITTE LLP
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, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, 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.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

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, 2016, and identifies the respective portions thereof that we have evaluated reported on to the Company's management/Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
			M$	M$	M$	M$
Deloitte LLP	Tourmaline Oil Corp. Reserve estimation and economic evaluation December 31, 2016	Canada	-	$2,042,515	-	$2,042,515

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

7. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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.

Deloitte LLP
700, 850 – 2nd Street
Calgary, Alberta T2P 0R8

Original signed by: "Andrew R. Botterill"
Andrew R. Botterill, P. Eng.
Partner

Execution date: January 31, 2017

SCHEDULE "C"

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 Petroleum Consultants 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 7th day of March, 2017.

(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) *"Robert W. Blakely"*
Robert W. Blakely
Director

(signed) *"Phillip A. Lamoreaux"*
Phillip A. Lamoreaux
Director

SCHEDULE "D"

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;

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

3. To enhance the external auditor's independence;

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

5. To strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management of Tourmaline ("**Management**") and external auditors.

Membership of Committee

1. 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 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 identifying, monitoring and mitigating 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; and
   - obtain explanations of significant variances with comparative reporting periods.

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

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 be entitled to a second or casting vote.

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

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

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer 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.

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.

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 Messrs. Blakely (Chair), Lamoreaux, MacDonald and Ms. Angevine. Each of the members of the Audit Committee is considered "financially literate" and each is 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 the 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)]
	($)	($)	($)	($)
2016......................	1,055,000	100,000	57,800	–
2015......................	812,500	100,000	30,250	–
2014......................	787,500	100,000	126,389	–

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".