TOURMALINE OIL CORP.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2014

March 9, 2015

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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**") and in the Canadian Oil and Gas Evaluation Handbook Volume I (the "**COGE Handbook**"). 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, 2014. 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

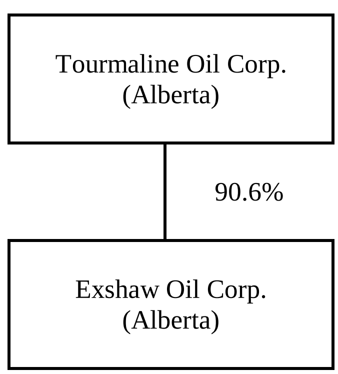
Name, address and incorporation

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, 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 intermediate 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 and land acquisitions combined with its active capital exploration and development program, Tourmaline has increased current production to 145,000 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, Sunrise/Dawson NEBC Montney and the Peace River High Regional Charlie Lake.

To date, the Company has raised approximately $2.6 billion through private placement equity financings and public offerings, approximately $366 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 natural gas price environment.

Business Strategy

Tourmaline's long-term business strategy is to increase shareholder value by building an extensive asset base over two to 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

2012

On April 4, 2012, Tourmaline completed a private placement of 1,402,000 "flow-through" Common Shares at a price of $28.80 per share for aggregate gross proceeds of approximately $40.4 million.

On August 30, 2012, Tourmaline completed a public offering of 4,600,000 Common Shares and a concurrent private placement of 39,000 Common Shares at a price of $29.00 per share for aggregate gross proceeds of approximately $134.5 million.

On November 1, 2012, Tourmaline completed a public offering of 1,000,000 "flow-through" Common Shares and a concurrent private placement of 50,000 "flow-through" Common Shares at a price of $36.90 per share for aggregate gross proceeds of approximately $38.7 million.

On November 30, 2012, Tourmaline acquired all of the outstanding shares of Huron in consideration for the issuance of approximately 7.4 million Common Shares.

2013

On March 12, 2013, Tourmaline completed a public offering of 5,750,000 Common Shares and 750,000 "flow-through" Common Shares and a concurrent private placement of 30,000 Common Shares and 85,000 "flow-through" Common Shares at a price of $34.25 per Common Share and $42.15 per "flow-through" Common Share for aggregate gross proceeds of approximately $233.2 million.

On October 8, 2013, Tourmaline completed a public offering of 3,450,000 Common Shares and 850,000 "flow-through" Common Shares and a concurrent private placement of 45,000 Common Shares and 75,000 "flow-through" Common Shares at a price of $41.75 per Common Share and $51.60 per "flow-through" Common Share for aggregate gross proceeds of approximately $193.6 million.

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 share for aggregate gross proceeds of approximately $219.2 million.

On April 24, 2014, the Company closed the acquisition of Santonia with the issuance of 3.228 million Tourmaline shares with a closing price on that date of $54.94 per Tourmaline 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 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.

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
			$1,487.9	26,910	1,070,109	694,968

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.

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[20]	
	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]	$15,963,021	Nil	Nil
	144,831,375	**$ 2,575,950,886**	**$ 365,994,665**	**14.21%**

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) 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 30 km southwest of Fort St. John, NEBC ("**Sunrise/Dawson 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. 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.

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, and Fahler-Notikewin Formations). Accordingly, each section in the Alberta Deep Basin core area is expected to include one or two targeted multi-phase stimulated horizontal wells in the Company's long-term development plan. Management estimates that up to 4,000 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 2015 capital exploration and development program, with in excess of 80 horizontal wells currently planned. As developed, future reserves will utilize the natural gas infrastructure that has been, and continues to be, constructed. In addition, the Company has 2,750 vertical development locations and 450 outer foothills thrust belt vertical wells with geologic and economic parameters similar to those of the horizontal inventory.

Tourmaline has ownership interests in six natural gas plants in the Alberta Deep Basin, five of which, the Wild River 14-20 plant (100% owned), the Hinton 6-32 gas plant (100% owned), the Minehead 15-12 plant (100% owned), the Anderson 1-9 plant (100% owned) and the Musreau 8-13 plant (100% owned), are operated by Tourmaline. In addition, Tourmaline owns and operates a substantial compression and dehydration facility at Horse capable of processing approximately 100 MMcf/d of natural gas. In aggregate, Tourmaline has in excess of 500 MMcf/d of natural gas processing capability within this plant network with plans to add an additional 100 MMcf/d by expanding the Wild River plant (50 MMcf/d) and constructing a new 50 MMcf/d plant at Edson in the second half of 2015. 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 reduce costs of operating the Alberta Deep Basin assets.

In the Alberta Deep Basin, Tourmaline drilled 29 gross natural gas wells in 2009, drilled 49 gross natural gas wells as well as 10 recompletions in 2010, drilled 52 gross natural gas wells in 2011, drilled 41 gross natural gas wells in 2012, drilled 68 gross natural gas wells in 2013 and 109 gross natural gas wells in 2014. Tourmaline's net production in the Alberta Deep Basin is currently estimated at approximately 90,000 Boe/d with further production growth anticipated through the balance of the year. Year-end 2014 proved plus probable reserves were 478 MMboe in the Alberta Deep Basin, with approximately 487 (403 net) future drilling locations recognized in the Consolidated Reserve Report.

Sunrise/Dawson/Sundown NEBC Montney

Tourmaline's second core exploration and production area on the greater 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 Montney in the NEBC play area. It is in this Groundbirch/Sunrise/Dawson area of the Peace River Arch where senior management of Tourmaline gained extensive experience with Duvernay and where Tourmaline has concentrated its exploration and production program.

The Company has assembled its large Montney position primarily through acquisitions completed between 2009 and 2013. In NEBC, Tourmaline has an inventory of approximately 1,100 gross horizontal Montney development drilling locations in the Sunrise/Dawson area, making the Company one of the largest participants in this resource play. In the Sunrise/Dawson complex in NEBC, Tourmaline has drilled 140 Montney multi-stage fracture-stimulated horizontal natural gas wells with an additional 40 Montney horizontal wells which are planned for the balance of 2015.

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 2016/2017. Tourmaline owns and operates four significant natural gas processing facilities with aggregate capacity of 250 MMcf/d with related gas gathering systems and NGL handling infrastructure. The Company is also planning a 50 MMcf/d expansion of an existing facility in the first half of 2016. Current production in the complex is approximately 225 MMcf/d of natural gas with 4,000 bbls per day of associated natural gas liquids. Tourmaline holds approximately 170 sections of Montney rights in the core area with 306 MMboe of proved plus probable reserves evaluated by the independent engineers at December 31, 2014 including approximately 290 (245 net) future drilling locations recognized in the Consolidated Reserve Report (as defined herein).

Peace River High Regional Charlie Lake

The third core area also on 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 16,000 Boe/d, 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 94 horizontal Charlie Lake oil wells to date and plans an additional 40 horizontals through the balance of 2015.

Proved plus probable reserves in the area at December 31, 2014 are estimated to be 72 MMboe including approximately 232 (162 net) future drilling locations recognized in the Consolidated Reserve Report. The Company currently owns and operates a significant oil battery capable of handling 20,000 bpd of fluids and the associated natural gas is delivered to a third party for processing. Tourmaline constructed a 30 MMcf/d sour gas processing facility which came on-stream in 2014 with a plant expansion adding an additional 45 MMcf/d planned for the second half of 2015.

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 11, 2015 and effective as at December 31, 2014.

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, 2014, with a preparation date of February 11, 2015 (the "**GLJ Reserve Report**") and the report of Deloitte LLP ("**Deloitte**") dated effective December 31, 2014, with a preparation date of February 11, 2015 (the "**Deloitte Reserve Report**"), which are contained in the consolidated report of GLJ dated effective December 31, 2014, with a preparation date of February 11, 2015 (the "**Consolidated Reserve Report**"). The Consolidated Reserve Report evaluated, as at December 31, 2014, 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 78% of the assigned total proved plus probable reserves and 78% of the total proved plus probable future net revenue discounted at 10%. Deloitte evaluated in the Deloitte Reserve Report approximately 22% of the assigned total proved plus probable reserves and 22% 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 including GLJ's cost assumptions. 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, 2015 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 0.56% of the assigned total proved plus probable reserves and 0.80% 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.

Substantially all of the Company's consolidated reserves are in Canada and, more specifically 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 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)

Summary of Crude Oil and Natural Gas Reserves and
Net Present Values of Future Net Revenue
as of December 31, 2014
Forecast Prices and Costs[2]

	Light & Medium Crude Oil		Natural Gas		NGL		Total Oil Equivalent	
Reserves Category	**Company Gross (Mbbls)**	**Company Net (Mbbls)**	**Company Gross (MMcf)**	**Company Net (MMcf)**	**Company Gross (Mbbls)**	**Company Net (Mbbls)**	**Company Gross (Mboe)**	**Company Net (Mboe)**
Proved Developed Producing	5,221	4,296	927,402	832,187	17,806	13,961	177,595	156,955
Proved Developed Non-Producing	788	667	111,064	101,813	2,584	2,130	21,883	19,766
Proved Undeveloped..............................	12,533	10,118	1,379,013	1,254,212	30,141	25,876	272,510	245,029
Total Proved Reserves.........................	18,542	15,080	2,417,480	2,188,212	50,532	41,968	471,988	421,750
Total Probable Reserves	19,100	14,847	1,925,204	1,721,195	43,457	35,478	383,424	337,191
Total Proved Plus Probable Reserves	37,642	29,927	4,342,684	3,909,407	93,989	77,446	855,411	758,941

Net Present Values Of Future Net Revenue ($000s)

	Before Future Income Taxes Discounted at (%/year)					After Future Income Taxes Discounted at [1] (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
Reserves Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	**($/Mcfe)**	**($/Boe)**
Proved Developed Producing	3,700,161	2,883,296	2,377,331	2,036,178	1,791,403	3,700,161	2,883,296	2,377,331	2,036,178	1,791,403	2.52	15.15
Proved Developed Non-Producing	454,890	347,286	280,893	236,445	204,793	454,890	347,286	280,893	236,445	204,793	2.37	14.21
Proved Undeveloped	4,385,925	2,739,687	1,811,003	1,235,096	852,600	3,388,925	2,141,586	1,422,502	967,501	659,929	1.23	7.39
Total Proved Reserves	8,540,977	5,970,270	4,469,227	3,507,720	2,848,796	7,543,976	5,372,169	4,080,726	3,240,125	2,656,125	1.77	10.60
Total Probable Reserves	9,218,494	5,080,233	3,197,753	2,188,766	1,585,230	6,884,206	3,754,448	2,330,697	1,570,631	1,119,241	1.58	9.48
Total Proved Plus Probable Reserves	17,759,471	11,050,503	7,666,980	5,696,486	4,434,026	14,428,183	9,126,617	6,411,423	4,810,756	3,775,366	1.68	10.10

Notes:

(1) 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 corporate tax situation, or tax planning. It does not provide an estimate of the value at the level of the corporation 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 corporation.

(2) Numbers may not add due to rounding.

Total Future Net Revenue ($000s)
(Undiscounted)
as of December 31, 2014
Forecast Prices and Costs

Reserves Category	**Revenue**	**Royalties**	**Operating Costs**	**Development Costs**	**Abandonment and Reclamation Costs**	**Future Net Revenue Before Deducting Future Income Tax Expenses**	**Future Income Tax Expenses**	**Future Net Revenue After Future Income Tax Expenses[1]**
Proved Producing…….................	6,060,229	756,755	1,530,619	50	72,644	3,700,161	-	3,700,161
Proved Developed Non-Producing	749,434	88,128	144,483	58,997	2,936	454,890	-	454,890
Proved Undeveloped……………..	9,803,579	1,155,706	1,610,998	2,603,199	47,751	4,385,925	997,001	3,388,925
Total Proved……………………...	16,613,242	2,000,589	3,286,100	2,662,246	123,330	8,540,977	997,001	7,543,976
Total Probable……………………	16,447,504	2,273,658	2,950,021	1,947,731	57,600	9,218,494	2,334,288	6,884,206
Total Proved Plus Probable………	33,060,747	4,274,247	6,236,121	4,609,977	180,931	17,759,471	3,331,288	14,428,183

Note:

(1) 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 corporate tax situation, or tax planning. It does not provide an estimate of the value at the level of the corporation, 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 corporation.

Future Net Revenue
by Production Group
as of December 31, 2014
Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)	Unit Value (discounted at 10%/year) ($/Mcfe)	($/Boe)
Proved Producing	Light and Medium Crude Oil	227,234	3.77	22.62
	Natural Gas (including by-products but excluding solution gas)	2,150,097	2.44	14.64
	Total	**2,377,331**	**2.52**	**15.15**
Total Proved	Light and Medium Crude Oil	464,048	2.43	14.55
	Natural Gas (including by-products but excluding solution gas)	4,005,179	1.71	10.27
	Total	**4,469,227**	**1.77**	**10.60**
Proved Plus Probable	Light and Medium Crude Oil	887,165	2.37	14.20
	Natural Gas (including by-products but excluding solution gas)	6,779,815	1.62	9.73
	Total	**7,666,980**	**1.68**	**10.10**

Reconciliation of Changes in Reserves

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

	Light and Medium Crude Oil			Natural Gas		
Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**
December 31, 2013	13,329	13,631	26,960	1,622,891	1,403,234	3,026,125
Discoveries	0	0	0	40,645	46,795	87,439
Extensions	10,339	8,785	19,124	609,286	411,048	1,020,344
Infill Drilling	0	0	0	150,184	-54,015	96,169
Improved Recovery	0	0	0	-9,293	-6,499	-15,792
Technical Revisions	-169	-1,525	-1,693	122,586	46,966	169,552
Acquisitions	447	1,358	1,805	119,159	93,794	212,953
Dispositions	-3,884	-3,156	-7,040	-24,361	-16,035	-40,396
Economic Factors	0	7	7	-111	-83	-194
Production	-1,521	0	-1,521	-213,506	0	-213,506
December 31, 2014	**18,542**	**19,100**	**37,642**	**2,417,480**	**1,925,202**	**4,342,684**

Factors	NGL Proved (Mbbl)	NGL Probable (Mbbl)	NGL Proved Plus Probable (Mbbl)	BOE Proved (Mbbl)	BOE Probable (Mbbl)	BOE Proved Plus Probable (Mbbl)
December 31, 2013	32,478	26,112	58,590	316,288	273,616	589,904
Discoveries	2,001	2,458	4,459	8,775	10,257	19,032
Extensions	12,799	9,621	22,420	124,686	86,914	211,600
Infill Drilling	790	119	909	25,821	-8,884	16,937
Improved Recovery	4,080	2,821	6,901	2,531	1,738	4,269
Technical Revisions	-679	395	-284	19,583	6,697	26,280
Acquisitions	3,295	2,073	5,368	23,602	19,063	42,665
Dispositions	-172	-144	-316	-8,116	-5,972	-14,088
Economic Factors	-1	0	-1	-20	-6	-26
Production	-4,057	0	-4,057	-41,162	0	-41,162
December 31, 2014	**50,532**	**43,457**	**93,989**	**471,988**	**383,422**	**855,411**

Notes to Reserves Data Tables:

(1) Numbers may not add due to rounding.

(2) Tourmaline has no unconventional reserves (bitumen, synthetic crude oil, natural gas from coal or heavy oil).

(3) Gross reserves do not include royalty interests received by Tourmaline.

(4) The crude oil, natural gas liquids and 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 and disconnect costs were estimated and included in the GLJ report at the individual entity level for all wells that were assigned reserves. No allowance for surface lease reclamation and salvage value was included. No abandonment costs have 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												
			NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma									Alberta Natural Gas Liquids (Then Current Dollars)			
Year	Inflation[2] %	Bank of Canada Average Noon Exchange Rate $US/$Cdn[3]	Constant 2015 $ $US/Bbl	Then Current $US/ Bbl	ICE BRENT Near Month Futures Contract Crude Oil FOB North Sea Then Current $Cdn/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 Stream Quality at Hardisty Then Current $Cdn/Bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current $Cdn/Bbl	Light 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	Spec Ethane $Cdn/Bbl	Edmonton Propane $Cdn/Bbl	Edmonton Butane $Cdn/Bbl	Edmonton Pentanes Plus $Cdn/Bbl
2015 Q1..........	1.8	0.8533	64.17	64.17	68.50	67.89	58.17	57.48	51.86	66.85	64.36	10.29	26.83	52.02	73.48
2015 Q2..........	1.8	0.8533	64.17	64.17	68.50	67.89	58.17	57.48	51.86	66.85	64.36	10.29	26.83	52.02	73.48
2015 Q3..........	1.8	0.8533	64.17	64.17	68.50	67.89	58.17	57.48	51.86	66.85	64.36	10.29	26.83	52.02	73.48
2015 Q4..........	1.8	0.8533	64.17	64.17	68.50	67.89	58.17	57.48	51.86	66.85	64.36	10.29	26.83	52.02	73.48
2015 Full Year	1.8	0.8533	64.17	64.17	68.50	67.89	58.17	57.48	51.86	66.85	64.36	10.29	26.83	52.02	73.48
2016...............	1.8	0.8683	75.29	76.67	81.03	83.52	71.57	70.74	63.90	82.29	79.19	11.71	37.22	63.44	90.17
2017...............	1.8	0.8683	80.38	83.33	87.70	90.96	77.99	77.07	69.64	89.66	86.34	12.46	43.88	69.02	98.20
2018...............	1.8	0.8683	82.49	87.08	90.67	95.26	81.63	80.70	72.93	93.87	90.31	13.57	46.58	72.35	102.69
2019...............	1.8	0.8683	84.34	90.67	94.27	99.33	85.12	84.12	76.03	97.87	94.10	14.67	48.52	75.52	106.99
2020...............	1.8	0.8683	86.12	94.30	97.95	103.80	88.93	87.87	79.45	102.26	98.27	15.34	50.77	78.96	111.73
2021...............	1.8	0.8683	86.61	96.59	99.52	106.16	90.95	89.88	81.25	104.58	100.49	16.00	52.02	80.74	114.26
2022...............	1.8	0.8683	86.61	98.36	101.36	108.10	92.61	91.53	82.74	106.49	102.32	16.64	53.04	82.22	116.34
2023...............	1.8	0.8683	86.62	100.18	103.21	110.09	94.29	93.19	84.25	108.45	104.17	17.29	54.09	83.75	118.47
2024...............	1.8	0.8683	86.62	102.02	105.13	112.13	96.05	94.91	85.85	110.46	106.11	17.79	55.16	85.33	120.67
2025+.............	1.8	0.8683	86.62	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr

	Natural Gas and Sulphur Pricing														
					Alberta Plant Gate				Saskatchewan Plant Gate			British Columbia			
	Henry Hub Nymex Near Month Contract				Spot										
Year	Constant 2015 $ $US/ MMbtu	Then Current $US/MMbtu	Midwest Price @ Chicago Then Current $US/ MMbtu	AECO/NIT Spot Then Current $Cdn/ MMbtu	Constant 2015 $ $/MMbtu	Then Current $MMbtu	ARP $/ MMbtu	Alliance $/MMbtu	SaskEnergy $/MMbtu	Spot $MMbtu	Sumas Spot $US/ MMbtu	Westcoast Station 2 $/MMbtu	Spot Plant Gate $MMbtu	Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gas $Cdn/LT
2015 Q1	3.29	3.29	3.49	3.38	3.16	3.16	3.16	2.78	3.26	3.29	3.43	3.28	3.05	122.14	93.69
2015 Q2	3.29	3.29	3.34	3.38	3.16	3.16	3.16	2.78	3.26	3.29	3.43	3.28	3.05	122.14	93.69
2015 Q3	3.29	3.29	3.34	3.38	3.16	3.16	3.16	2.78	3.26	3.29	3.43	3.28	3.05	122.14	93.69
2015 Q4	3.29	3.29	3.39	3.38	3.16	3.16	3.16	2.78	3.26	3.29	3.43	3.28	3.05	122.14	93.69
2015 Full Year	3.29	3.29	3.39	3.38	3.16	3.16	3.16	2.78	3.26	3.29	3.43	3.28	3.05	122.14	93.69
2016...........	3.70	3.77	3.87	3.83	3.54	3.60	3.60	3.22	3.70	3.74	3.87	3.73	3.50	111.14	77.33
2017...........	3.88	4.02	4.12	4.06	3.69	3.83	3.83	3.50	3.93	3.97	4.10	3.96	3.73	111.54	77.80
2018...........	4.12	4.35	4.45	4.41	3.96	4.19	4.19	3.87	4.29	4.33	4.46	4.31	4.09	113.20	79.69
2019...........	4.35	4.68	4.78	4.76	4.21	4.53	4.53	4.23	4.63	4.67	4.82	4.66	4.43	114.90	81.64
2020...........	4.47	4.89	4.99	4.97	4.33	4.74	4.74	4.45	4.84	4.88	5.03	4.87	4.63	116.61	83.61

Natural Gas and Sulphur Pricing

	Henry Hub Nymex Near Month Contract				Alberta Plant Gate				Saskatchewan Plant Gate			British Columbia			
					Spot										
Year	Constant 2015 $ $US/ MMbtu	Then Current $US/MMbtu	Midwest Price @ Chicago Then Current $US/ MMbtu	AECO/NIT Spot Then Current $Cdn/ MMbtu	Constant 2015 $ $/MMbtu	Then Current $MMbtu	ARP $/ MMbtu	Alliance $/MMbtu	SaskEnergy $/MMbtu	Spot $MMbtu	Sumas Spot $US/ MMbtu	Westcoast Station 2 $/MMbtu	Spot Plant Gate $MMbtu	Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gas $Cdn/LT
2021...........	4.56	5.08	5.18	5.18	4.42	4.93	4.93	4.68	5.03	5.08	5.22	5.07	4.83	118.36	85.61
2022...........	4.63	5.26	5.36	5.36	4.50	5.11	5.11	4.88	5.21	5.26	5.40	5.25	5.01	120.16	87.66
2023...........	4.70	5.44	5.54	5.54	4.58	5.29	5.29	5.07	5.39	5.44	5.58	5.43	5.19	121.97	89.74
2024...........	4.75	5.59	5.69	5.70	4.63	5.45	5.45	5.24	5.55	5.60	5.74	5.58	5.34	123.83	91.86
2025+.........	4.74	+1.8%/yr	+1.8%/yr	+1.8%/yr	4.62	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/yr	+1.8%/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 GLJ, Sproule Associates Ltd. and McDaniel & Associates Consultants Ltd. as at December 31, 2014 (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, 2014, the Company received the following weighted average prices, including realized gains and losses on financial instruments, in respect of its production: natural gas – $4.58/Mcf; NGL – $36.07/bbl; and oil – $89.17/bbl. The overall weighted average price received by Tourmaline on an oil equivalent basis was $33.05/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, 2014, 2013 and 2012.

Proved Undeveloped Reserves

	Light and Medium Crude Oil (Mbbls)		**Natural Gas (MMcf)**		**NGL (Mbbls)**		**Boe Oil Equivalent (Mbbls)**	
Year	**First Attributed**[(1)]	**Total at Year-end**	**First Attributed**	**Total at Year-end**	**First Attributed**	**Total at Year-end**	**First Attributed**	**Total at Year-end**
2012	2,940	5,460	271,689	764,973	4,041	13,213	52,262	146,168
2013	3,973	8,731	260,889	936,636	4,638	18,169	52,092	183,005
2014	6,602	12,533	408,287	1,379,014	9,813	30,142	84,463	272,510

Note:

(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

It is anticipated that most of the proved undeveloped locations will be drilled by December 31, 2017.

Probable Undeveloped Reserves

	Light and Medium Crude Oil (Mbbls)		**Natural Gas (MMcf)**		**NGL (Mbbls)**		**Boe Oil Equivalent (Mbbls)**	
Year	**First Attributed**[(1)]	**Total at Year-end**	**First Attributed**	**Total at Year-end**	**First Attributed**	**Total at Year-end**	**First Attributed**	**Total at Year-end**
2012	2,200	9,540	328,933	1,590,122	5,597	27,046	62,619	301,606
2013	6,617	10,458	486,803	1,158,421	8,371	21,249	96,122	224,777
2014	8,282	15,902	574,473	1,578,330	14,772	36,783	118,799	315,740

Note:

(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

It is anticipated that most of the future development capital associated with the probable undeveloped reserves will be incurred by December 31, 2019.

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 five 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

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

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**
2015	858,374	971,324
2016	951,305	1,119,508
2017....................	658,271	1,140,210
2018....................	154,008	840,784
2019....................	40,288	472,298
2020....................	0	65,704
Thereafter	0	149
Total...................	**2,662,246**	**4,609,977**

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, 2014, 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)	153	107.50	15	10.12	766	567.65	251	174.09
British Columbia(1)	1	0.19	0	0.00	149	125.80	62	49.00
Saskatchewan(1)	16	0.89	0	0.00	0	0.00	0	0.00
Total	**170**	**108.58**	**15**	**10.12**	**915**	**693.45**	**313**	**223.09**

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, 2014, in which Tourmaline has an interest.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	498,380	328,986	1,469,785	1,128,668	1,968,165	1,457,654
British Columbia	59,302	37,351	190,579	141,377	249,881	178,727
Saskatchewan	970	37	73,922	65,930	74,892	65,967
Total(1)	**558,652**	**366,373**	**1,734,287**	**1,335,975**	**2,292,939**	**1,702,348**

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.

The following table sets out Tourmaline's developed and undeveloped properties as at March 2, 2015, in which Tourmaline has an interest.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	503,980	333,673	1,360,985	1,082,566	1,864,966	1,416,239
British Columbia	59,302	39,293	189,272	140,069	248,574	179,362
Saskatchewan	970	37	73,760	65,930	74,730	65,967
Total(1)	**564,252**	**373,003**	**1,624,017**	**1,288,566**	**2,188,270**	**1,661,568**

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

Tourmaline has approximately 1.7 million gross undeveloped acres (1.3 million net undeveloped acres). Proved undeveloped reserves have been assigned to approximately 200,000 of these net acres. There are no material work commitments in respect of these properties. Tourmaline expects that rights to explore, develop and/or exploit up to 0.3 million gross acres (527 net sections) of its undeveloped land holdings could expire by December 31, 2015.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

See "Additional Information Relating to Reserves Data – Significant Factors or Uncertainties" above.

Additional Information Concerning Abandonment Costs

The December 31, 2014, reserve report provides for the abandonment of 1,492 net wells. The total abandonment costs in respect of proved and probable reserves using forecast prices are $180.9 million (undiscounted) and $22.4 million (discounted at 10%). One hundred percent of such amounts were deducted as abandonment costs in estimating Tourmaline's future net revenue in respect of proved and probable reserves as disclosed above.

The following table sets forth abandonment costs deducted in the estimation of Tourmaline's future net revenue:

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

Year	Abandonment Costs (Undiscounted)	Abandonment Costs (Discounted at 10%)
2015	262	250
2016	994	862
2017	1,219	961
Thereafter	178,456	20,307
Total	**180,931**	**22,380**

The year end reserve report includes estimated abandonment costs of $2.5 million (undiscounted) to be incurred over the next three years.

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 2019. Tourmaline has approximately $4.3 billion of tax pools available as at December 31, 2014, which can be used to offset taxable income in future years.

Capital Expenditures

The following table summarizes capital expenditures (including property acquisitions and net of dispositions, as well as capitalized general administrative expenses) related to Tourmaline's activities for the year ended December 31, 2014:

	$000's
Exploration, drilling and completions	1,210,700
Development, equipping and facilities	314,774
Property acquisitions(1)	33,027
Property dispositions(2)	(500,639)
Equipment and facilities	474,604

	$000's
Geological and geophysical	10,358
Other (including capitalized G&A)	20,742
Total[3][4]	**1,563,566**

Notes:

(1) Property acquisitions are a result of approximately $23.4 million of acquired proved properties and approximately $9.6 million of acquired unproved properties.
(2) Property dispositions include $442.6 million in proved properties and $58.0 million in unproved properties.
(3) Includes capital expenditures related to Exshaw (without reduction to reflect the 9.4% third-party minority interest in Exshaw).
(4) Excludes non-cash corporate acquisition of Santonia which resulted in increased property, plant and equipment of $167.5 million and exploration and evaluation assets of $19.1 million.

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, 2014:

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Natural Gas	11	10.51	162	136.01
Oil	2	2.00	31	27.73
Service	–	–	–	–
Dry	–	–	–	–
Total[1]	**13**	**12.51**	**193**	**163.74**

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, 2015 as evaluated by GLJ and Deloitte, which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data" above.

	Light and Medium Crude Oil		Natural Gas		NGL		Oil Equivalent Total	
Reserves Category	**Company Gross (bbl/d)**	**Company Net (bbl/d)**	**Company Gross (Mcf/d)**	**Company Net (Mcf/d)**	**Company Gross (bbl/d)**	**Company Net (bbl/d)**	**Company Gross (bbl/d)**	**Company Net (bbl/d)**
Proved Producing	3,871	3,361	520,856	479,565	10,022	8,531	100,702	91,820
Proved Developed Non-Producing	733	678	71,545	67,981	1,622	1,510	14,279	13,518
Proved Undeveloped	3,274	3,101	178,677	170,313	3,096	2,917	36,149	34,404
Total Proved	7,878	7,141	771,078	717,860	14,740	12,958	151,130	139,742
Total Probable	532	485	78,358	73,975	1,739	1,617	15,331	14,431
Total Proved Plus Probable	8,410	7,625	849,436	791,835	16,479	14,575	166,461	154,173

Notes:

(1) No one field accounted for 20% or more of Tourmaline's estimated 2015 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 2014[4]			
	December 31	September 30	June 30	March 31
Average Daily Production[1]				
Light and Medium Crude Oil (Bbl/d)	10,004	9,002	9,713	8,689
Natural Gas (Mcf/d)	692,604	562,739	562,912	525,999
NGL (Bbls/d)	5,507	5,205	6,421	6,207
Combined (Boe/d)	130,944	107,997	109,953	102,563
Average Price Received				
Light and Medium Crude Oil (S/bbl)	71.11	94.77	98.31	94.17
Natural Gas ($/Mcf)	4.09	4.34	4.71	5.38
NGL ($/bbl)	28.32	39.74	38.57	37.34
Combined ($/Boe)	28.25	32.41	35.03	37.84
Royalties Paid				
Light and Medium Crude Oil ($/bbl)	6.77	13.99	9.32	6.73
Natural Gas ($/Mcf)	0.20	0.28	0.41	0.41
NGL ($/bbl)	8.97	7.78	12.57	10.23
Combined ($/Boe)	1.96	2.97	3.65	3.31
Production Costs (includes transportation)				
Light and Medium Crude Oil ($/bbl)	13.49	13.29	15.38	15.44
Natural Gas ($/Mcf)	0.91	1.12	1.10	0.96
NGL ($/bbl)[2]	–	–	–	–
Combined ($/Boe)	6.06	7.25	7.37	6.59
Netback Received ($/Boe)[3]	20.23	22.19	24.02	27.94

Notes:

(1) Before deduction of royalties.
(2) NGL volumes are derived from natural gas production, as such all the related operating costs are attributed to the production of natural gas.
(3) Netbacks are calculated by subtracting royalties and operating costs from revenues.
(4) 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, 2014 for each of the important fields comprising Tourmaline's assets.

	Light and Medium Crude Oil (Bbls/d)	Natural Gas (Mcf/d)	NGL (Bbls/d)	Boe (Boe/d)
Alberta Deep Basin	2,914	383,181	4,395	71,173
Other Alberta properties	4,242	28,859	107	9,159
British Columbia properties	2,199	174,416	1,329	32,597
Total[1]	**9,355**	**586,456**	**5,831**	**112,929**

Note:

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

For the year ended December 31, 2014, approximately 72% of Tourmaline's gross revenue was derived from natural gas production and approximately 28% was derived from crude oil and NGL 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 the following, 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.

During the fourth quarter of 2014, Tourmaline produced 692,604 MMcf/d of natural gas. The Company has the following gas volumes hedged, either in full or in part, during 2015 and 2016:

	First Quarter 2015		**Full Year 2015**		**Full Year 2016**	
	Vol/d(1)	**Price(1)**	**Vol/d(1)**	**Price(1)**	**Vol/d(1)**	**Price(1)**
Fixed AECO (CAD) - Mcf	252,829	$4.45	244,758	$3.86	15,360	$3.47
Fixed Nymex (USD) - MMbtu	5,000	$4.21	16,726	$3.40	–	–
Basis Differentials (USD) - MMbtu	20,000	$(0.63)	45,945	$(0.57)	70,838	$(0.53)
Call Writers/Extendibles – MMbtu	7,586	$5.25	47,225	$3.96	134,511	$4.34

Notes:

(1) The volumes and prices reported are the weighted-average volumes and prices for the period.

The Company has the following oil volumes hedged during 2015 and 2016:

	First Quarter 2015		**Full Year 2015**		**Full Year 2016**	
	Vol/d(1)	**Price(1)**	**Vol/d(1)**	**Price(1)**	**Vol/d(1)**	**Price(1)**
Swaps (USD) - Bbl	1,700	$89.32	2,225	$79.00	400	$80.10
Costless Collars (USD) - Bbl	1,300	$81.15(2)	1,300	$81.15(2)	–	–
Call Writers/Extendibles(2) – Bbl	–	–	775	$60.52	1,200	$86.36

Notes:

(1) The volumes and prices reported are the weighted-average volumes and prices for the period.
(2) Ceiling $94.29.

Tourmaline's transportation obligations or commitments for future physical deliveries of crude oil and natural gas are not expected to exceed 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. The Canadian Association of Petroleum Producers estimates that there are over 1,000 exploration and production companies in Canada. Tourmaline controls less than one percent of the business in Western Canada, but where it is active (see "Description of Core Long-Term Growth Areas"), Tourmaline believes it has a strong competitive position.

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, 2014, Tourmaline had 140 full time employees and 4 consultants located at its Calgary office, and 34 full time employees and 106 contract operators in various field locations. Tourmaline currently has 139 full time employees and 6 consultants located at its Calgary office, and 33 full time employees and 106 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. Tourmaline's credit facility prohibits 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
2014	**59.25**	**34.47**	**156,721,578**
January	49.44	44.24	11,127,780
February	51.45	45.84	8,827,757
March	52.32	47.99	8,611,509
April	57.34	51.59	8,842,489
May	57.66	52.34	8,654,517
June	59.25	53.31	6,759,216
July	58.73	50.37	11,878,961
August	55.15	49.80	11,590,052
September	55.17	48.53	17,054,585
October	50.00	38.10	22,051,932
November	43.97	37.63	17,948,982
December	42.90	34.47	23,373,798

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 2014

Date of Issuance	Number of Options	Exercise Price of Options
January 15, 2014	200,000	$45.80
February 15, 2014	145,000	$48.16
March 15, 2014	30,000	$48.99
June 4, 2014	540,000	$53.80
June 15, 2014	335,000	$56.76
July 15, 2014	235,000	$55.05
August 15, 2014	370,000	$51.47
September 15, 2014	180,000	$51.88
October 15, 2014	347,500	$46.43
November 15, 2014	2,728,000	$42.78
December 15, 2014	120,000	$36.84

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the Company's knowledge, as of December 31, 2014, 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, 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 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
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	President and Chief Executive Officer of Nordegg Resources Inc., an oil and gas company, since March 2008. Prior thereto, President and Chief Executive Officer of RSX Energy Inc., an oil and gas company.	March 22, 2011
Robert W. Blakely(1)(2)(3)(5) 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) 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	Managing Member of Lamoreaux Capital Management LLC, an investment management company.	September 9, 2010
Andrew B. MacDonald(1)(2)(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

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since
Clayton H. Riddell Alberta, Canada	Director	Chairman and Chief Executive Officer of Paramount Resources Ltd., an oil and gas company.	October 27, 2008
Brian G. Robinson Alberta, Canada	Director and Vice President, Finance and Chief Financial Officer	Director and Vice President, Finance and Chief Financial Officer of Tourmaline since August 2008. Prior thereto, Vice President, Finance and Chief Financial Officer of Duvernay.	October 27, 2008
Robert N. Yurkovich(6) Alberta, Canada	Director and Executive Vice President, Exploration	Director and Executive Vice President, Exploration of Tourmaline since October 2008. Prior thereto, Vice President, Exploration of Duvernay.	June 5, 2013
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
Allan J. Bush Alberta, Canada	Vice President, Operations and Chief Operating Officer	Vice President, Operations and Chief Operating Officer since February 2014. Prior thereto, Vice President, Production and Completions and Operations Engineering Manager of Tourmaline. Prior thereto, Completions and Operations Engineering Manager of Duvernay Oil Corp.	N/A
Tim A. Krysak Alberta, Canada	Vice President, Drilling	Vice President, Drilling of Tourmaline since May 2013. Prior thereto, Drilling Manager of Tourmaline. Prior thereto, Drilling 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

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 Committee. Mr. Lamoreaux is the Chairman of the Corporate Governance 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) Mr. Yurkovich acts primarily in an advisory capacity to the Executive Team. He also served as a director from October 27, 2008 to June 6, 2012.

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, 35,611,999 Common Shares or approximately 17.5% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of the Company, except as described below, 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.

Mr. Clayton Riddell is a director and executive officer of Paramount Resources Ltd. ("**Paramount**"). From 1992 to 2008, Paramount was the general partner of T.T.Y. Paramount Partnership No. 5 ("**TTY**"), a limited partnership, which was an unlisted reporting issuer in certain provinces of Canada. TTY was established in 1980 to conduct oil and gas exploration and development but had not carried on active operations since 1984 and had only nominal assets. A cease trade order against TTY was issued by the Autorité des marches financiers in 1999 for failing to file the June 30, 1998 interim financial statements in Québec. The cease trade order was revoked on April 9, 2008. TTY was dissolved on July 21, 2008.

Bankruptcies

To the knowledge of the Company, no director or executive officer of the Company (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company: (a) is, as of the date of this 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.

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 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 through agreements among the governments of Canada, Alberta, British Columbia, and Saskatchewan all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in Western Canada.

Pricing and Marketing

Oil

In Canada, the 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, prices are also influenced by regional market and transportation issues. 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 is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is 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. In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications" under Part VI of the *National Energy Board Act* (Canada).

Natural Gas

Alberta'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 such as the Alberta "NIT" (Nova Inventory Transfer), 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 (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) 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/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity 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.

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 other than Crown lands 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.

Alberta

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate 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 are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

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 non-Crown lands 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 fee simple 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**"). 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 level of the freehold production tax is based on the volume of monthly production. It 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 freehold production tax is either 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%.

As of January 1, 2017 all liquid natural gas ("**LNG**") facilities will be 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 British Columbia government will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

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;

- *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 also 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.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 6% minimum royalty on tier 1 wells and a 3% minimum royalty on tier 2 wells which claim the deep well/deep re-entry credits. The minimum royalty applies to tier 1 and tier 2 wells when the net royalty payable would otherwise be zero for a production month.

Saskatchewan

In Saskatchewan, taxes ("**Resource Surcharge**") and royalties are applicable to revenue generated by corporations 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 Company 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.

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 Saskatchewan government, 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 10^3 m^3/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 gigajoule for third and fourth-tier gas and $0.95 per gigajoule 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 well-head 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 will 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 licenses 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. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. 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, and Saskatchewan 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 license. On March 29, 2007, British Columbia expanded its policy of deep rights reversion for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their 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 licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license.

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, we 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 regulation pursuant to a variety of provincial and federal environmental legislation, 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. 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 such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

Federal

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 environment 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.

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. 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 the transformation to a single regulator is the creation of 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.

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, licenses, 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.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

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, 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, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements 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. The ABOGCA 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. 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 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 liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and

- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes will be implemented over a three-year period. The first phase was implemented in May of 2013, the second phase was implemented in May of 2014 and the final phase will be implemented in May of 2015. The changes to the AB LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On July 4, 2014, the AER introduced 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 will be required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*.

British Columbia

In British Columbia, the Commission implements the Liability Management Rating ("**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 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 Economy implements 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 liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

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.

The Government of Canada is 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 which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

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. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

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 CCEMA is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. 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 facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, 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. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities 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 and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration 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

In February 2008, 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 CO_2 equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, 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.

In the 2012 Budget, British Columbia announced that the government would undertake 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 last year, British Columbia confirmed that it will keep its revenue-neutral carbon tax, the current carbon tax rates and tax base will be maintained and revenues will continue to be returned through tax reductions.

On April 3, 2008, 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 Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. The *Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets 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. Recent amendments to the Cap and Trade Act repealed past requirements on public-sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under development.

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 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.

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 participations 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 assure a profit on the investment or recovery of drilling, completion and operating costs.

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, 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.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Worldwide crude oil commodity prices are expected to remain volatile in the near future as a result of global excess supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), and ongoing global credit and liquidity concerns. This volatility may affect the Company's ability to obtain equity or debt financing on acceptable terms.

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 or discovered by the Company. The Company's ability to market its oil and natural gas may depend upon its ability to acquire space 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 as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Company.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply 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 and may decline in the near future 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, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. A material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices.

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 acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the 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, 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.

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.

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 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, if disposed of, may realize less than their carrying value on the financial statements of the Company.

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.

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 over-runs 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 and hydraulic fracturing, 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 supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- 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 and pipeline systems some of which it does not own and 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, and in particular the processing facilities, 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. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Furthermore, 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 and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, the Company's financial condition, results of operations and cash flows.

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. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

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 search for, and the acquisition of, oil and natural gas properties and in the 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. 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, methods, and reliability of delivery and storage.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company. There can be no assurance that the Company will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by 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, its business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

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 other 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.

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. 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 to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Company's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

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.

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.

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 certain 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 laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the 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 becomes defunct. 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 of the ratio of the Company' deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. This is of particular concern to junior oil and gas companies as they may be disproportionately affected by price instability. See: "*Industry Conditions*".

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 will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. 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. 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. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition.

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 will negatively affect the Company's production revenues. Accordingly, Canadian/United States exchange rates could affect the future value of the Company's reserves as determined by independent evaluators.

To the extent that the Company engages in risk management activities related to 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.

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);
- 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. 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 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. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Company's access to additional financing may be affected.

Because of global economic volatility, the Company may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such 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. 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.

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. Even if the Company is able to obtain new financing, 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. 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.

The Company's lenders use the Company's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Company's borrowing base. A material decline in commodity prices could reduce the Company's borrowing base, reducing the funds available to the Company under the credit facility. This could result in the requirement to repay a portion, or all, of the Company's bank indebtedness.

Issuance of Debt

From time to time, the Company may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of 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) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities.

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.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. 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.

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

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

Actual production and cash flows derived from 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.

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.

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 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.

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.

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.

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.

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, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to 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.

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 commence 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.

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 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.

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. In addition, 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. 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.

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 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.

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

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 person 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.

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.

Hydraulic Fracturing

Due to recent seismic activity reported in the Fox Creek area of Alberta, the Alberta Energy Regulator has announced new seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay Zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to 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 Alberta Energy Regulator continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

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 risk 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 "Reader Advisory Regarding 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;
- 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 drilling rigs to be operated by the Company in 2015.

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.

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, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, 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).

3. 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.

4. The following table sets forth the estimated 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 by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation 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	Corporate Summary February 11, 2015	Canada	-	$6,009	-	$6,009

5. 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.

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

7. 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 19, 2015.

ORIGINALLY SIGNED BY

(signed) Chad P. Lemke, P. Eng

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, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, 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).

3. 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.

4. The following table sets forth the estimated 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 by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation 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
			MM$	MM$	MM$	MM$
Deloitte LLP	Tourmaline Oil Corp. Reserve Estimation and Economic Evaluation February 11, 2015	Canada	-	$1,659	-	$1,659

5. 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.

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

7. 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: "Douglas S. Ashton"
Douglas S. Ashton, P. Eng.
Partner
Execution date: February 13, 2015

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 which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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; 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 9th day of March, 2015.

(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 and MacDonald. 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)] ($)	All Other Fees[(4)] ($)
2014......................	787,500	100,000	126,389	–
2013......................	665,000	100,000	118,464	–
2012......................	576,500	100,000	13,050	–

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".