



## **2013 Annual Information Form**

**March 6, 2014**

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## ADVISORIES

### Cautionary Statement Regarding Forward-Looking Information and Statements

This Annual Information Form (“AIF”), including documents incorporated by reference, contains forward-looking information and statements (collectively “**forward-looking statements**”). These statements, which relate to future events or our future performance, are provided to allow readers to better understand our business and prospects and may not be suitable for other purposes. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as seek, anticipate, plan, continue, estimate, expect, may, will, project, predict, potential, targeting, intend, could, might, should, believe and similar expressions (including the negatives thereof). 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. We believe the expectations reflected in the forward-looking statements included in this AIF are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements speak only as of the date of this AIF. We assume no obligation to revise or update these statements except as required pursuant to applicable securities laws.

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

- Freehold Royalties Ltd.’s (“**Freehold**” or the “**Corporation**”) strategy with respect to future acquisitions and the possibility that the Board of Directors may vary the strategy in the future;
- the performance characteristics of our oil and natural gas properties;
- the estimated future value of the Corporation’s oil and natural gas reserves;
- projected oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- estimated abandonment and reclamation costs and the number of wells on which Freehold expects to have abandonment and reclamation obligations;
- plans for development of undeveloped reserves;
- the funding and payment of future dividends;
- the expectations for the funding of capital expenditures;
- supply and demand for oil and natural gas;
- the tax horizon and taxability of the Corporation;
- expectations regarding the ability to raise capital and add to reserves through acquisitions and development;
- the performance and characteristics of the oil and natural gas properties in which the Corporation has an investment;
- treatment under governmental regulatory regimes and tax laws;
- capital expenditure programs and the funding thereof;
- the expectation that our mineral title lands and gross overriding royalty interests will provide the majority of revenue;
- the intended focus of Freehold’s activities undertaken by the Manager towards maximizing dividends to be paid to the Shareholders and acquiring appropriate assets to provide long-term growth in the value of Freehold;
- the expectation that the activities undertaken by Freehold will maximize value to the Shareholders;
- the expectation that Freehold may acquire additional royalties and other forms of oil and natural gas related assets or may participate in development activities on working interest properties that have long-term value enhancement potential;
- the expectation that properties to be acquired may be operated by competent third parties or may require the Manager to assume operatorship on behalf of Freehold;
- that drilling activity on the Royalty Lands is anticipated to provide continued new sources of oil and natural gas Royalty Income in future years, with new wells and production therefrom reducing the rate at which production and Royalty Income would otherwise decline;
- the expectation that approximately 40% of our 2014 capital budget will be allocated to Freehold’s working interest properties in the Southeast Saskatchewan area and the balance will be allocated to various other

working interest properties, primarily on Freehold's mineral title lands in the Lloydminster area (heavy oil) and in west central Alberta (Cardium light oil).

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

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- risks related to the environment and changing environmental laws;
- geological, technical, drilling, and processing problems;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "*Risk Factors*".

Forward-looking statements are based on a number of factors and assumptions that have been used to develop such statements but which may prove to be incorrect. Although we believe that the assumptions underlying such forward-looking statements are reasonable, we can give no assurance that the plans, intentions or expectations upon which such forward-looking statements are based will occur. In addition to other factors and assumptions that may be identified in this AIF, assumptions have been made regarding, among other things:

- the impact of increasing competition;
- the general stability of the economic and political environment in which the Corporation has an interest in oil and natural gas properties;
- the timely receipt of any required regulatory approvals;
- the Manager's policies with respect to acquisitions and payments of dividends;
- the ability of the Manager to obtain qualified staff, equipment and services in a timely and cost efficient manner;
- drilling results;
- the ability of the operator of the projects that Freehold has an interest in to operate the field in a safe, efficient and effective manner;
- the ability of the Corporation to obtain financing on acceptable terms;
- field production rates and decline rates;
- the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration;
- the performance and characteristics of the oil and natural gas properties in which the Corporation has an interest;
- the timing and costs of pipeline, storage and facility construction and expansion and the ability of the operator of the properties in which the Corporation has an interest to secure adequate product transportation;
- future oil and natural gas prices;
- currency, exchange and interest rates;
- participation levels in the dividend reinvestment plan of Freehold;
- the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation has an interest in oil and natural gas properties; and
- the ability of the operator of the properties in which the Corporation has an interest to successfully market its oil and natural gas products. See "*Reserves Data – Significant Factors and Uncertainties*".

Statements relating to reserves are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement.

## Conversion of Natural Gas to Barrels of Oil Equivalent

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (“boe”). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio based on the current price of crude oil to natural gas is significantly different from the 6:1 energy equivalency ratio, using a conversion ratio on a 6:1 basis may be misleading as an indication of value.

## Presentation of Oil and Natural Gas Reserves and Production Information

All oil and natural gas reserve information contained in this AIF has been prepared and presented in accordance with National Instrument 51-101. The actual oil and natural gas reserves and future production will be greater than or less than the estimates provided in this AIF. The estimated future net revenue from the production of the disclosed oil and natural reserves does not represent the fair market value of these reserves.

## GLOSSARY OF TERMS

In this AIF, the following terms shall have the meanings set forth below, unless otherwise indicated:

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

“**Board of Directors**” means the Board of Directors of Freehold.

“**Canpar**” means Canpar Holdings Ltd., a wholly-owned subsidiary of the CN Pension Trust Funds.

“**CN Pension Trust Funds**” means the pension trust funds for employees of Canadian National Railway Company.

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

“**Common Shares**” means the common shares of Freehold.

“**Corporation**”, “**us**”, “**we**”, “**our**” or “**Freehold**” means Freehold Royalties Ltd., a corporation amalgamated under the ABCA. All references to the “Corporation”, “us”, “we”, “our” or “Freehold”, unless the context otherwise requires, are references to Freehold Royalties Ltd., its predecessors, its subsidiaries and partnerships.

“**Deferred Share Unit Plan**” means the deferred share unit plan for non-management directors of Freehold whereby fully vested Deferred Share Units are granted annually and dividends to Shareholders declared by the Corporation prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of dividends.

“**Deferred Share Units**” means the deferred share units of the Corporation issued pursuant to the Deferred Share Unit Plan that are redeemable for Common Shares any time after the retirement of a member of the Board of Directors.

“**DRIP**” means the dividend reinvestment plan of Freehold.

“**Freehold Resources**” means Freehold Resources Ltd., a corporation amalgamated under the ABCA and a wholly-owned subsidiary of the Corporation.

“**Governance Agreement**” means the governance agreement between the Manager and Freehold dated as of December 31, 2010.

“**Gross**” or “**gross**” means:

- in relation to production and reserves, our working interest (operating and non-operating) share before deduction of royalties and without including our royalty interests;
- in relation to wells, the total number of wells in which we have an interest; and
- in relation to properties, the total area of properties in which we have an interest.

“**Management Agreement**” means the amended and restated agreement dated January 1, 2011 among the Manager, the Corporation, Freehold Resources and the Partnership pursuant to which the Manager provides management services to the Corporation, Freehold Resources and the Partnership.

“**Management Fee**” means the fee payable to the Manager pursuant to the Management Agreement.

“**Manager**” means Rife Resources Management Ltd., a wholly-owned subsidiary of Rife.

“**Net**” or “**net**” means:

- in relation to production and reserves, our working interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interests;
- in relation to wells, the number of wells obtained by aggregating our working interest in each of its gross wells; and
- in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest owned by us.

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

“**NI 51-102**” means National Instrument 51-102 *Continuous Disclosure Obligations*.

“**Partnership**” means Freehold Royalties Partnership, a general partnership formed under the laws of Alberta.

“**Proved**” and “**probable**” reserves have the meanings given to those terms under “*Reserves Data - Disclosure of Reserves Data*”.

“**Rife**” means Rife Resources Ltd., a wholly-owned subsidiary of the CN Pension Trust Funds.

“**Royalty Income**” means income to the Corporation from its royalties in oil, natural gas and potash resources.

“**Royalty Lands**” means the lands from which the Corporation derives Royalty Income.

“**Seaton-Jordan**” means Seaton-Jordan & Associates Ltd., independent mineral management consultants of Calgary, Alberta.

“**Shareholders**” means the holders from time to time of Common Shares.

“**Tax Act**” means the *Income Tax Act* (Canada) and the regulations thereunder.

“**Trimble**” means Trimble Engineering Associates Ltd., independent qualified reserves evaluators of Calgary, Alberta.

“**Trimble Report**” means the report dated January 22, 2014 prepared by Trimble, evaluating the oil, natural gas, natural gas liquids, and sulphur reserves attributable to the Corporation as at December 31, 2013.

“**TSX**” means the Toronto Stock Exchange.

## Abbreviations

<b>AECO</b>	reference pricing point for natural gas at a natural gas storage facility near the Alberta-Saskatchewan border
<b>API</b>	American Petroleum Institute
<b>°API</b>	the measure of the density of liquid petroleum products derived from a specific gravity
<b>bbl and bbls</b>	barrel and barrels, respectively, each barrel representing 34.972 imperial gallons or 42 U.S. gallons
<b>bbls/d</b>	barrels per day
<b>boe</b>	barrels of oil equivalent
<b>boe/d</b>	barrels of oil equivalent per day
<b>Mbbls</b>	one thousand barrels
<b>Mboe</b>	one thousand barrels of oil equivalent
<b>MMbbls</b>	one million barrels
<b>MMboe</b>	one million barrels of oil equivalent
<b>MMBtu</b>	one million British Thermal Units
<b>Mcf</b>	one thousand cubic feet
<b>Mcf/d</b>	one thousand cubic feet per day
<b>MMcf</b>	one million cubic feet
<b>MMcf/d</b>	one million cubic feet per day
<b>NGL</b>	natural gas liquids
<b>WTI</b>	West Texas Intermediate

## Conversion Factors

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
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	0.4047
hectares	acres	2.471

All dollar amounts set forth in this AIF are in Canadian dollars, except where otherwise indicated.

## CORPORATE STRUCTURE

### General

Freehold is a dividend paying oil and gas corporation based in Calgary, which, directly or indirectly, acquired all of the assets and assumed all of the liabilities of Freehold Royalty Trust pursuant to a plan of arrangement completed on January 1, 2011. Under the plan of arrangement, Freehold Royalties Ltd. and 1555014 Alberta Ltd. were amalgamated under the ABCA to form Freehold.

Freehold enables its Shareholders to participate in the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold, Freehold Resources and the Partnership. The head, principal and registered office of Freehold is located at Suite 400, 144 – 4<sup>th</sup> Avenue SW, Calgary, Alberta, T2P 3N4.

### Freehold Resources Ltd.

All of the issued and outstanding shares of Freehold Resources are held by Freehold. The head, principal and registered office of Freehold Resources is located at Suite 400, 144 – 4<sup>th</sup> Avenue SW, Calgary, Alberta, T2P 3N4.

### Rife Resources Management Ltd.

The Manager was incorporated under the *Corporations Act* (Ontario) on March 5, 1968 under the name “75-89 Gosford Limited” and continued under the *Canada Business Corporations Act* on April 20, 1979. The Manager changed its name to “Rife Resources Management Ltd.” on October 1, 1996. Pursuant to the Management Agreement, Freehold, Freehold Resources and the Partnership retained the Manager for the purposes of identifying, evaluating and assisting with the acquisition, disposition and ongoing management and administration of the royalties, working interest properties and other oil, natural gas and potash resources held by Freehold, Freehold Resources and the Partnership. The head, principal and registered office of the Manager is located at Suite 400, 144 – 4<sup>th</sup> Avenue SW, Calgary, Alberta, T2P 3N4.

Pursuant to an agreement between Rife and the Manager, Rife provides the Manager, which is a wholly-owned subsidiary of Rife, on a contract basis, with all necessary personnel, equipment and facilities required to provide management and operational services to Freehold, Freehold Resources and the Partnership on a cost recovery basis. Freehold benefits from the fact that Rife has been in operation for more than 30 years and many of the personnel utilized by the Manager have extensive experience with the assets underlying Freehold’s royalty and working interest properties and other oil, natural gas and potash resources. In addition, Rife manages two private corporations that are engaged in similar business ventures as Freehold. To effectively manage these private corporations and Freehold, Freehold Resources and the Partnership, Rife has assembled a larger, more diversified and more experienced staff than Freehold could otherwise retain to manage its assets. Management of Freehold believes these organizational and synergistic benefits are advantageous to the Shareholders. Rife and the Manager also ensure that Freehold receives priority to consider acquisition opportunities. In addition, the Management Fee paid to the Manager is paid in Common Shares, which the Board believes aligns the interests of the Manager with the interests of the Shareholders. Based on these factors, the Board believes that maintaining Freehold’s relationship with the Manager is in the best interests of Freehold.

Pursuant to the Governance Agreement, the Manager is entitled to nominate for election two individuals as directors of Freehold provided that the Manager and its affiliates, including the CN Pension Trust Funds, hold 10% or more of the issued and outstanding Common Shares. If the Manager and its affiliates hold less than 10% of the issued and outstanding Common Shares, the Manager will have the right to nominate for election one individual as a director of Freehold. If the individuals nominated by the Manager fail to get elected or if the Manager ceases to hold any Common Shares (in which case the Manager will not have the right to nominate any individuals as directors of Freehold) but continues to act as manager of Freehold pursuant to the Management Agreement, the Governance Agreement will provide the Manager with the right to have an observer present at all meetings of directors of Freehold. The CN Pension Trust Funds currently holds, directly or indirectly, approximately 27% of the outstanding Common Shares and as a result, has the right to nominate two individuals as directors of Freehold.

## Freehold Royalties Partnership

The Partnership is a general partnership formed under the laws of Alberta. On December 13, 2010, the Partnership changed its name from “Petrovera Resources” to “Freehold Royalties Partnership”. Freehold and Freehold Resources are the general partners of the Partnership. Freehold is the managing partner of the Partnership. The head office of the Partnership is located at Suite 400, 144 – 4<sup>th</sup> Avenue SW, Calgary, Alberta, T2P 3N4.

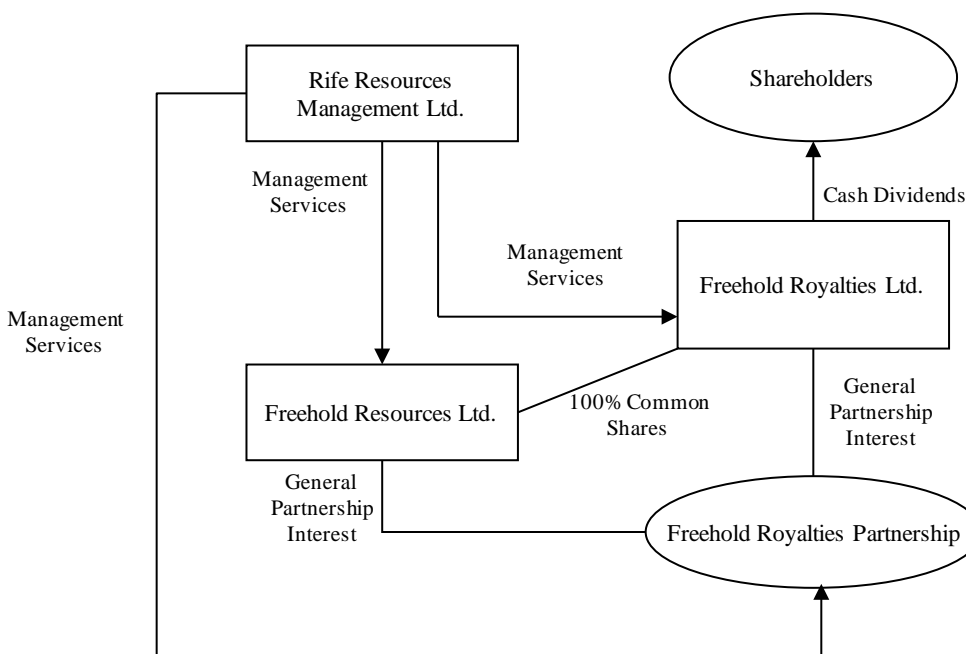
## Structure of the Corporation

The following table provides the name, the percentage of voting securities owned by the Corporation and the jurisdiction of incorporation, continuance or formation of the Corporation’s subsidiaries and partnerships, either direct or indirect, as at the date hereof.

	Percentage of Voting Securities (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/ Formation
Freehold Resources Ltd.	100%	Corporation	Alberta
Freehold Royalties Partnership	100%	General Partnership	Alberta

## Organizational Structure of the Corporation

The following diagram sets forth the organizational structure of Freehold.



## GENERAL DEVELOPMENT OF BUSINESS

The following is a summary description of the development of our business since January 1, 2011.

### Year Ended December 31, 2011

On September 30, 2011, we closed an acquisition of certain royalty interests for \$7.3 million, after closing adjustments, which added approximately 125 boe per day of primarily light oil to our royalty production base commencing in the fourth quarter of 2011. We acquired a 10% gross overriding royalty interest on 5,048 gross acres of land in the Peace River area of Northwest Alberta. The acquisition supported our strategy of focusing on oil and gas royalties and was accretive on a debt-adjusted per share basis. The acquisition was effective July 1, 2011 and was funded through our existing credit facilities.

**Year Ended December 31, 2012**

On January 17, 2012, we completed the acquisition of royalty interests on certain producing and non-producing lands in Alberta, British Columbia and Saskatchewan for \$49.3 million after closing adjustments. The acquisition was funded with money drawn on our credit facilities. As a result of the acquisition, we receive an average 4% contractual gross overriding royalty on over 250,000 gross acres (including over 51,000 undeveloped acres valued at \$1.3 million).

On February 29, 2012, we issued 3,450,000 Common Shares under a short-form prospectus offering at a price of \$20.50, which included 450,000 Common Shares issued pursuant to an over-allotment option provided to the underwriters. The net proceeds of approximately \$67.6 million were used to reduce bank debt.

On August 31, 2012, we acquired approximately 6,100 net acres of leased mineral title lands in Alberta and Saskatchewan. The lands and 90 boe per day (21% royalty production) were purchased for \$10.9 million after closing adjustments. The acquisition was funded with money drawn on our credit facilities.

**Year Ended December 31, 2013**

In 2013, the Corporation completed five transactions involving the acquisition of mainly royalty interests, primarily in Alberta, for \$10.1 million, including adjustments, which added approximately 100 boe per day of production.

**Significant Acquisitions**

During the year ended December 31, 2013, the Corporation did not complete any acquisitions that would be considered significant pursuant to NI 51-102.

## BUSINESS OF THE CORPORATION

**Overview**

Freehold is an Alberta-based, dividend-paying corporation with a focus on royalty assets. Freehold receives revenue from properties as oil, natural gas, and potash are produced. Freehold has a diverse production base, with interests in more than 31,000 oil and natural gas wells throughout western Canada. This includes significant mineral title and gross overriding royalty interests that will provide the majority of revenue. Royalties offer the benefit of sharing in production, without exposure to the capital, operating and environmental costs associated with oil, natural gas, and potash production. Oil, natural gas, and potash are finite resources. Over time, reserves are depleted and capital investment is required to sustain production and cash flow.

**Management Policies and Acquisition Strategy**

The Manager manages Freehold, Freehold Resources and the Partnership in accordance with the Management Agreement. All activities undertaken by the Manager are directed towards maximizing dividends to be paid to the Shareholders while striving to acquire appropriate assets to provide long-term growth in the value of Freehold. These two objectives are fundamental to the operation of Freehold and are pursued to maximize value to the Shareholders.

The Manager utilizes its staff's extensive experience and employs prudent oil and gas business practices to increase the assets of Freehold through the acquisition of both royalty and working interest oil and natural gas properties.

Freehold may, directly or indirectly through its subsidiaries and partnerships, acquire additional royalties and other forms of oil and natural gas related assets or may participate in development activities on working interest properties that are primarily of a low risk nature and that have long-term value enhancement potential. Properties to be acquired may be operated by competent third parties or may require Freehold to manage.

Freehold's acquisition strategy targets individual properties, or groups of properties with a bias toward royalty interests, to provide long-term growth in value. The key criteria are:

- quality assets;
- attractive returns;
- reasonable evaluation assumptions; and
- long economic life.

These criteria serve as guidelines for the Manager on presenting acquisitions for approval by the Board of Directors. The Board of Directors may vary these criteria for any particular acquisition based on the Manager's recommendations and consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life index and asset quality.

The acquisition of additional royalties by Freehold includes existing contractual royalties and newly created royalties. With respect to new royalties, the purchase price paid by Freehold may include two components: an amount paid at closing for a royalty on existing production and an amount paid towards the drilling of a predetermined number of future wells, which may be paid on completion of a specific operational event.

## RESERVES DATA

The statement of reserves data and other oil and natural gas information of the Corporation is set forth below (the "**Statement**"). The effective date of the Statement is December 31, 2013, and the preparation date of the Statement is January 22, 2014.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Reserves Data and Other Information in Form 51-101F3 are attached as Appendices A and B, respectively.

### Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by an independent qualified reserves evaluator, Trimble, with an effective date of December 31, 2013 contained in the Trimble Report. The Reserves Data summarizes the oil, natural gas, natural gas liquids, and sulphur reserves of Freehold and the net present values of future net revenue for these reserves using forecast prices and costs. The Trimble Report has been prepared in accordance with NI 51-101 and the standards and reserves definitions contained in the COGE Handbook. Information not required by NI 51-101 has been presented to provide continuity and additional information that we believe is important to the readers of this information. Freehold engaged Trimble to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Freehold's reserves are in Canada and, specifically, in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, and Ontario.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Freehold's crude oil, natural gas, natural gas liquids, and sulphur reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas, natural gas liquids, and sulphur reserves may be greater than or less than the estimates provided herein.

**Forecast Prices and Costs**

**SUMMARY OF OIL AND GAS RESERVES  
AS OF DECEMBER 31, 2013  
FORECAST PRICES AND COSTS**

Reserves Category	Light and Medium Oil		Heavy Oil		Total Crude Oil	
	Gross <sup>(1)</sup> (Mbbbls)	Net (Mbbbls)	Gross <sup>(1)</sup> (Mbbbls)	Net (Mbbbls)	Gross <sup>(1)</sup> (Mbbbls)	Net (Mbbbls)
Proved						
Developed producing	1,722	3,415	748	4,167	2,471	7,582
Developed non-producing	104	91	16	14	120	105
Undeveloped	-	-	-	-	-	-
Total proved	1,827	3,506	764	4,181	2,591	7,687
Probable	1,456	2,322	851	2,730	2,307	5,052
Total proved plus probable	3,283	5,828	1,615	6,911	4,898	12,739

Reserves Category	Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross <sup>(1)</sup> (MMcf)	Net (MMcf)	Gross <sup>(1)</sup> (Mbbbls)	Net (Mbbbls)	Gross <sup>(1)</sup> (Mboe)	Net (Mboe)
Proved						
Developed producing	3,400	30,887	131	846	3,168	13,576
Developed non-producing	586	622	44	35	262	244
Undeveloped	-	3,734	-	42	-	664
Total proved	3,986	35,243	175	923	3,430	14,483
Probable	4,363	18,385	237	513	3,271	8,629
Total proved plus probable	8,349	53,627	412	1,436	6,702	23,113

- (1) Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include royalties receivable. Net reserves are comprised of working interests minus royalties payable plus royalties receivable. The Corporation is unique in that the majority of our assets are royalty interests. This causes our gross reserves to be lower than our net reserves and may hinder an investor's ability to compare our reserves with others in our industry.

**SUMMARY OF  
NET PRESENT VALUES  
OF FUTURE NET REVENUE  
AS OF DECEMBER 31, 2013  
FORECAST PRICES AND COSTS**

Reserves Category	Before Income Taxes, Discounted at (% per year)				
	0% (\$000s)	5% (\$000s)	10% (\$000s)	15% (\$000s)	20% (\$000s)
Proved					
Developed producing	756,691	558,106	448,309	379,056	331,345
Developed non-producing	6,640	4,908	3,989	3,423	3,036
Undeveloped	20,139	13,417	9,422	6,882	5,184
Total proved	783,470	576,431	461,721	389,361	339,566
Probable	532,947	280,416	184,316	136,501	108,128
Total proved plus probable	1,316,417	856,847	646,037	525,862	447,693

Reserves Category	After Income Taxes, Discounted at (% per year)				
	0%	5%	10%	15%	20%
	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)
Proved					
Developed producing	634,088	467,455	375,628	317,755	277,886
Developed non-producing	4,938	3,595	2,879	2,438	2,137
Undeveloped	15,042	10,021	7,036	5,139	3,870
Total proved	654,068	481,071	385,544	325,331	283,893
Probable	396,944	208,014	136,175	100,447	79,257
Total proved plus probable	1,051,012	689,085	521,719	425,778	363,150

**TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2013  
FORECAST PRICES AND COSTS**

(\$000s)	Reserves Category	
	Proved	Proved Plus Probable
Royalty Income	684,094	1,113,378
Revenue from working interest properties	286,536	565,905
Royalty expense on working interest properties	(44,686)	(95,158)
Operating costs	(130,578)	(240,560)
Development costs	(2,583)	(16,007)
Well abandonment and reclamation costs	(9,312)	(11,141)
Future net revenue before income taxes	783,470	1,316,417
Future income taxes	(129,402)	(265,404)
Future net revenue after income taxes	654,068	1,051,012

**FUTURE NET REVENUE  
BY PRODUCTION GROUP  
AS OF DECEMBER 31, 2013  
FORECAST PRICES AND COSTS**

Reserves Category	Production Group	Future Net Revenue Before Income Taxes	Unit Value <sup>(1)</sup>
		Discounted at 10% per year (\$000s)	(\$)
Proved	Light and Medium Oil (including solution gas and other by-products)	174,416	49.75/bbl
	Heavy Oil (including solution gas and other by-products)	178,061	42.59/bbl
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	109,244	3.55/Mcf
	Total Proved	461,721	31.88/boe
Proved plus probable	Light and Medium Oil (including solution gas and other by-products)	254,870	43.73/bbl
	Heavy Oil (including solution gas and other by-products)	246,313	35.64/bbl
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	144,853	3.11/Mcf
	Total Proved Plus Probable	646,037	27.95/boe

(1) The Unit Value is calculated by dividing the discounted Future Net Revenue by the net reserves for the principal product of the Production Group.

## Definitions and Other Notes

1. Columns may not add due to rounding.
2. The oil, natural gas, natural liquids, and sulphur reserve estimates presented in the Trimble Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is 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.

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.

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

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived

quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

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

### 3. Forecast Prices and Costs

Forecast prices and costs are those:

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

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Oil and natural gas benchmark reference pricing, inflation and exchange rates as at December 31, 2013 utilized in the Trimble Report were as follows:

#### FORECAST PRICES USED IN ESTIMATES AS OF DECEMBER 31, 2013

Year	Oil					Natural Gas	Natural Gas Liquids FOB Field Gate			Inflation Rate	Exchange Rate
	WTI Cushing Oklahoma	Edmonton Par Price 40° API	Hardisty Heavy 12° API	Hardisty Bow River 24.9° API	Western Canada Select 20.5° API	AECO 30 Day Spot	Propane	Butane	Pentane		
	\$US/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	MMBtu	\$Cdn/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	%/ Year	\$US/\$ Cdn
2014	94.65	92.64	70.40	78.74	77.81	4.00	45.78	69.05	103.50	1.50	0.94
2015	88.37	89.31	67.88	75.92	75.02	3.99	44.14	66.57	99.78	1.50	0.94
2016	84.25	89.63	68.12	76.19	75.29	4.00	44.30	66.81	100.14	1.50	0.94
2017	95.52	101.62	77.23	86.38	85.36	4.93	50.22	75.74	113.53	1.50	0.94
2018	96.96	103.14	78.39	87.67	86.64	5.01	50.98	76.88	115.24	1.50	0.94
2019	98.41	104.69	79.57	88.99	87.94	5.09	51.74	78.03	116.97	1.50	0.94
2020	99.89	106.26	80.76	90.32	89.26	5.18	52.52	79.20	118.72	1.50	0.94
2021	101.38	107.86	81.97	91.68	90.60	5.26	53.30	80.39	120.50	1.50	0.94
2022	102.91	109.47	83.20	93.05	91.96	5.35	54.10	81.60	122.31	1.50	0.94
2023	104.45	111.12	84.45	94.45	93.34	5.43	54.92	82.82	124.14	1.50	0.94
2024	106.02	112.78	85.71	95.86	94.74	5.52	55.74	84.06	126.01	1.50	0.94
Thereafter, per year:											
	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	1.50	0.94

The following table provides the historical weighted average prices realized by Freehold for the year ended December 31, 2013:

#### FREEHOLD WEIGHTED AVERAGE PRICES YEAR ENDED DECEMBER 31, 2013

	Light and Medium Oil (\$/bbl)	Heavy Oil (\$/bbl)	Natural Gas (\$/Mcf)	Natural Gas Liquids (\$/bbl)	Oil Equivalent (\$/boe)
Freehold weighted average price	87.92	66.51	2.55	58.98	55.06

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

5. "Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
- gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, natural gas lines and power lines, to the extent necessary in developing the reserves;
  - drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
  - acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
  - provide improved recovery systems.
6. "Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.
7. Future Development Costs

The following table sets forth development costs deducted in the estimation of Freehold's future net revenue attributable to the reserve categories noted below, based on forecast prices and costs:

Year	Forecast Prices and Costs	
	Proved Reserves (undiscounted) (\$000s)	Proved Plus Probable Reserves (undiscounted) (\$000s)
2014	1,388	8,228
2015	237	5,290
2016	180	1,509
2017	628	664
2018	74	127
Remainder	76	189
<b>Total</b>	<b>2,583</b>	<b>16,007</b>

The source of funding for future development costs will be internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue will not be materially affected by the costs of funding the future development expenditures.

- The forecast price and cost assumptions assume the continuance of current laws and regulations.
- The extent and character of all factual data supplied to Trimble were accepted by Trimble as represented. No field inspection was conducted.
- The after-tax net present value calculation of the Corporation's reserves reflects the tax burden on the Corporation's properties on a standalone basis, utilizing our tax pools to the maximum depreciation rate as currently permitted. It does not consider the corporate-level tax situation, or tax planning. It does not provide an estimate of the value at the corporate level, which may be significantly different. See our financial statements and accompanying management's discussion and analysis for additional tax information.

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

### Reconciliation of Changes in Reserves

The table below is a reconciliation of gross reserves and is provided as a requirement of NI 51-101. Due to the Corporation's unique asset base, we feel that they do not provide adequate information and are potentially

misleading. Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include any royalties receivable. Net reserves are working interests minus royalties payable plus royalties receivable. As the majority of the Corporation's assets are royalty interests, they are excluded from this table. This hinders an investor's ability to compare our reserves to others in our industry. Therefore in addition to presenting the reconciliation using gross reserves, we have also presented the reconciliation using net reserves.

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

	Light and Medium Oil			Heavy Oil		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus
			Probable (Mbbbls)			Probable (Mbbbls)
December 31, 2012	1,826	1,346	3,173	856	916	1,771
Extensions	367	304	671	134	65	199
Improved recovery	-	-	-	-	-	-
Technical revisions	184	(190)	(6)	90	(131)	(41)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic factors	7	(4)	2	2	2	3
Production	(558)	-	(558)	(318)	-	(318)
<b>December 31, 2013<sup>(1)</sup></b>	<b>1,827</b>	<b>1,456</b>	<b>3,283</b>	<b>764</b>	<b>851</b>	<b>1,615</b>

	Natural Gas			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus
			Probable (MMcf)			Probable (Mbbbls)
December 31, 2012	4,083	3,042	7,125	154	124	277
Extensions	661	1,693	2,354	48	121	169
Improved recovery	-	-	-	-	-	-
Technical revisions	193	(378)	(186)	13	(7)	6
Discoveries	-	-	-	-	-	-
Acquisitions	87	45	132	-	-	-
Dispositions	-	-	-	-	-	-
Economic factors	(57)	(38)	(95)	(1)	(1)	(2)
Production	(981)	-	(981)	(39)	-	(39)
<b>December 31, 2013<sup>(1)</sup></b>	<b>3,986</b>	<b>4,363</b>	<b>8,349</b>	<b>175</b>	<b>237</b>	<b>412</b>

	Oil Equivalent			
		Proved (Mboe)	Probable (Mboe)	Proved Plus
				Probable (Mboe)
December 31, 2012		3,516	2,893	6,409
Extensions		659	772	1,432
Improved recovery		-	-	-
Technical revisions		319	(391)	(72)
Discoveries		-	-	-
Acquisitions		14	8	22
Dispositions		-	-	-
Economic factors		(2)	(10)	(12)
Production		(1,077)	-	(1,077)
<b>December 31, 2013<sup>(1)</sup></b>		<b>3,430</b>	<b>3,271</b>	<b>6,702</b>

(1) Columns may not add due to rounding.

The following reserve reconciliation table is provided as an aid to the investor. The table is based on net reserves and is consistent with our disclosure in previous years.

**RECONCILIATION OF COMPANY NET RESERVES  
BY PRINCIPAL PRODUCT TYPE  
FORECAST PRICES AND COSTS**

	Light and Medium Oil			Heavy Oil		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2012	3,554	2,301	5,855	4,178	3,197	7,376
Extensions	495	382	878	155	81	236
Improved recovery	-	-	-	-	-	-
Technical revisions	374	(356)	18	636	(677)	(41)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	82	128	210
Dispositions	-	-	-	-	-	-
Economic factors	(4)	(5)	(9)	(1)	-	-
Production	(914)	-	(914)	(870)	-	(870)
<b>December 31, 2013<sup>(1)</sup></b>	<b>3,506</b>	<b>2,322</b>	<b>5,828</b>	<b>4,181</b>	<b>2,730</b>	<b>6,911</b>

	Natural Gas			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2012	38,736	20,212	58,949	893	476	1,369
Extensions	814	1,494	2,309	48	102	150
Improved recovery	-	-	-	-	-	-
Technical revisions	1,831	(3,433)	(1,602)	181	(64)	117
Discoveries	-	-	-	-	-	-
Acquisitions	361	140	501	-	-	-
Dispositions	-	-	-	-	-	-
Economic factors	(55)	(29)	(84)	-	(1)	(1)
Production	(6,445)	-	(6,445)	(199)	-	(199)
<b>December 31, 2013<sup>(1)</sup></b>	<b>35,243</b>	<b>18,385</b>	<b>53,627</b>	<b>923</b>	<b>513</b>	<b>1,436</b>

	Oil Equivalent		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2012	15,082	9,343	24,425
Extensions	835	814	1,649
Improved recovery	-	-	-
Technical revisions	1,496	(1,669)	(174)
Discoveries	-	-	-
Acquisitions	142	152	293
Dispositions	-	-	-
Economic factors	(14)	(11)	(25)
Production	(3,057)	-	(3,057)
<b>December 31, 2013<sup>(1)</sup></b>	<b>14,483</b>	<b>8,629</b>	<b>23,113</b>

(1) Columns may not add due to rounding.

## Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards in the COGE Handbook.

At December 31, 2013, proved undeveloped reserves assigned in the Trimble Report were 4.6% of the total proved reserves assigned.

At December 31, 2013, probable undeveloped reserves were 5.3% of the total proved plus probable reserves assigned in the Trimble Report.

The light, medium and heavy oil net undeveloped reserves are expected to be developed over the next two years. Development of the undeveloped natural gas and natural gas liquids net reserves will be dependent on commodity pricing and it may be three or more years until they are developed.

The following tables set forth the proved undeveloped reserves and the probable undeveloped net reserves by product type, attributed to Freehold's assets for the years ended December 31, 2013, 2012, and 2011, and in the aggregate before that time, based on forecast prices and costs:

### INITIAL PROVED UNDEVELOPED NET RESERVES FIRST ATTRIBUTED BY YEAR FORECAST PRICES AND COSTS

Year	Light and Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)
Prior	-	-	-	-
2011	-	-	-	-
2012	-	-	3,734	42
2013	-	-	-	-
Total Booked for Current Year	-	-	3,734	42

### INITIAL PROBABLE UNDEVELOPED NET RESERVES FIRST ATTRIBUTED BY YEAR FORECAST PRICES AND COSTS

Year	Light and Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)
Prior	-	12	502	-
2011	43	-	44	-
2012	138	195	2,166	31
2013	-	94	1,102	78
Total Booked for Current Year	181	301	3,814	109

## Significant Factors or Uncertainties

The reserve and recovery information contained in the Trimble Report are only estimates and the actual production and ultimate reserves may be greater or less than the estimates prepared by Trimble.

The value of the Common Shares will depend upon, among other things, the reserves attributable to the Corporation's properties. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the Corporation's properties will vary from estimates and those variations could be material. The reserve and cash flow information contained in this Statement represents estimates only. Reserves and estimated future net cash flow from the Corporation's properties have been evaluated by Trimble, an independent qualified reserves evaluator. Trimble considers a number of factors and makes assumptions when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices;
- assumptions about future production levels, development costs and capital expenditures;

- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- timing and amount of capital expenditures;
- marketability of production;
- future prices of oil and natural gas;
- operating costs and royalties; and
- other government levies that may be imposed over the producing life of reserves.

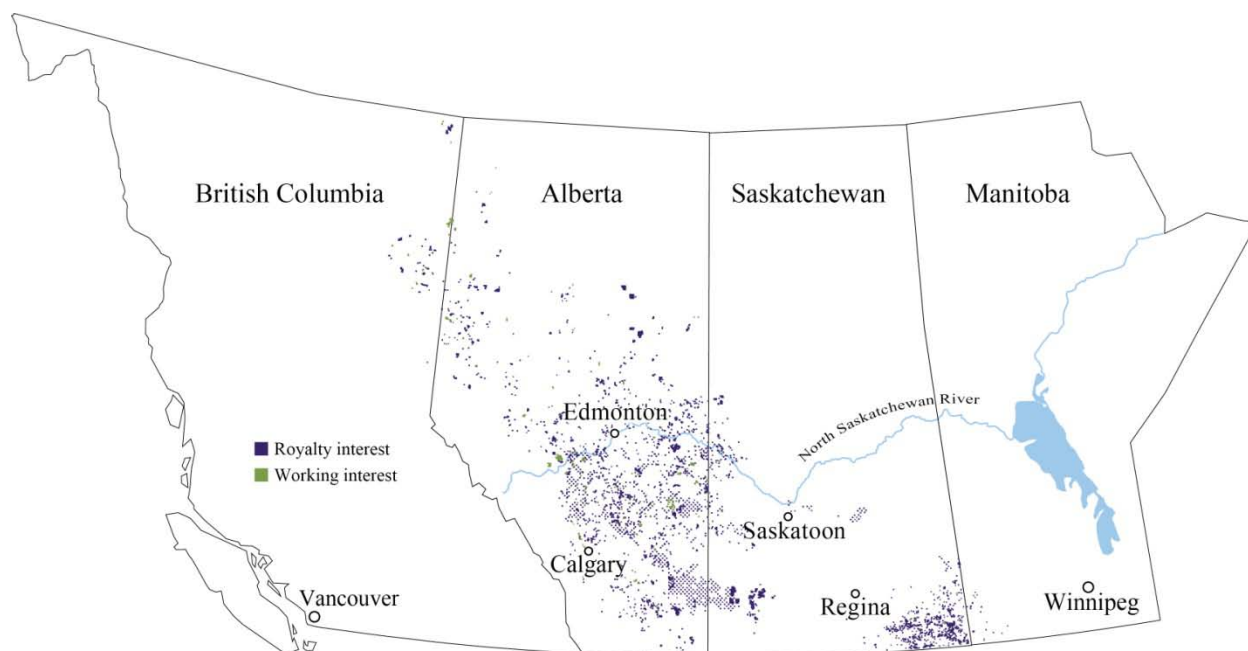
These factors and assumptions were based on prices at the date the evaluation was prepared. If these factors and assumptions prove to be inaccurate, the actual results may vary materially from the reserve estimates. Many of these factors are subject to change and are beyond the Corporation's control. For example, the evaluation is based in part on the assumed success of exploitation activities intended to be undertaken in future years. Actual reserves and estimated cash flows will be less than those contained in the evaluation to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation. Furthermore, cash flows may differ from those contained in the evaluation depending upon whether capital expenditures and operating costs differ from those estimated in the evaluation.

## DESCRIPTION OF PROPERTIES

Freehold has oil and natural gas interests in producing and non-producing lands located in British Columbia, Alberta, Saskatchewan, Manitoba, and Ontario, encompassing approximately 3.1 million gross acres at December 31, 2013. The majority of our land (70%) is in Alberta, with 16% in Saskatchewan, 9% in Ontario, 5% in British Columbia, and less than 1% in Manitoba. We also own royalty interests in seven potash mines in Saskatchewan.

Producing lands include Crown, freehold, unitized and non-unitized oil and natural gas and potash production. The properties are operated by experienced operators, including, among others: Apache Canada Ltd., ARC Resources Ltd., Bellatrix Exploration Ltd., Bonterra Energy Corp., Canadian Natural Resources Limited, Cenovus Energy Inc., ConocoPhillips Canada, Crescent Point Energy Corp., Delphi Energy Corp., Devon Canada, Encana Corporation, Harvest Operations Corp., Husky Oil Operations Limited, Legacy Oil & Gas Ltd., Lightstream Resources Ltd., Long Run Exploration Ltd., NAL Resources Limited, Northern Blizzard Resources Inc., Pemoco Ltd., Pengrowth Energy Corporation, Penn West Petroleum Ltd., Perpetual Energy Inc., PotashCorp., Renegade Petroleum Ltd., Rife, Shell Canada Limited, Spyglass Resources Corp., Talisman Energy Canada, Taqa North Ltd. and Whitecap Resources Inc.

Over 90% of our gross land holdings are royalty interests, from which we derive the majority of our income.



In the following discussion, all references to reserves are net, utilizing forecast prices and costs, before tax. All references to royalty production are net, and all references to working interest production are gross. 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.

## **Royalty Interests**

The unique characteristics of royalties provide royalty holders with special commercial benefits not available to the working interest owner because the royalty holder enjoys the upside potential of the property with reduced risk. A royalty interest differs significantly from a working interest in that a holder of a royalty interest is generally not responsible for, and has no obligation to contribute additional funds for any purpose, including operating or capital costs, or environmental or reclamation liabilities; whereas a holder of a working interest is liable for its share of capital, operating and environmental costs, usually in proportion to its ownership percentage, and it receives its pro rata share of revenue.

The Corporation's royalty reserves are derived from: (i) leased mineral title lands that are owned by the Corporation and upon which the lessees pay lessor royalties to the Corporation; (ii) royalty assumption lands which are mineral title properties owned by third parties in respect of which royalties are reserved to the Corporation and which, by their terms, are expressed to be interests in land; and (iii) gross overriding royalty lands leased by third parties upon which such third parties pay contractual royalties or net profits interests to the Corporation, which may or may not be interests in land. Mineral title and royalty assumption lands do not expire, while gross overriding royalties may expire at the end of the lease's productive life. Mineral title lands and royalty assumption lands derived from mineral titles are the most valuable category of Royalty Lands, because the rights are held in perpetuity.

### ***Mineral Title Lands***

Royalty revenue is derived from the royalties payable to the Corporation (lessor) in the form of lessor royalties through the lease documents issued to the companies (lessees) that have producing wells located thereon. In 2013, this category of land accounted for 19% of our total royalty acreage and provided approximately 45% of our royalty revenue.

The Corporation has ownership interests in mineral titles ranging from 10% to 100% and recovers the applicable royalty, ranging from 10% to 22.5%, of all oil and natural gas products produced or sold from the leased lands. For example, if the Corporation's interest in a mineral title property is 50% and the royalty rate applicable to the lease is 20% then the Corporation would be entitled to receive the proceeds from the sale of 10% (50% x 20%) of the oil or natural gas produced for the period.

The Corporation's mineral title lands encompass approximately 532,000 acres, of which 80% are leased and 20% are unleased. The mineral title lands also include approximately 171,000 undeveloped acres, representing potential for further development. The majority of Freehold's mineral title lands are in areas south of the North Saskatchewan River, in the watershed of the Hudson Bay. The majority of Freehold's unleased mineral title lands are in southeast Saskatchewan.

The Corporation also holds mineral title interests in potash, as described on page 22.

### ***Royalty Assumption Lands***

The Corporation holds royalty interests in approximately 95,000 acres of mineral title lands, of which approximately 22,000 acres are undeveloped. These mineral title properties, referred to as royalty assumption lands, are owned by a number of third party oil and gas companies in respect of which royalties (varying from 4.7% to 6.5%) have been reserved to the Corporation. As the royalty interests with respect to the royalty assumption lands are a title royalty representing, by their terms, an interest in land, these royalties are held in perpetuity. In 2013, this category of land accounted for 3% of our total royalty acreage and provided approximately 4% of our royalty revenue.

### Gross Overriding Royalty Lands

The Corporation holds gross overriding royalties in approximately 2,220,000 acres, of which approximately 588,000 acres are undeveloped. The gross overriding royalties are contractual in nature and therefore are not held in perpetuity but rather expire upon the termination of the lease(s) or agreement(s). These lands consist of properties leased by a number of third party oil and gas companies in respect of which contractual royalties or net profits interests have been reserved to the Corporation. In 2013, this category of land accounted for 78% of our total royalty acreage and provided approximately 51% of our royalty revenue.

The granting of a gross overriding royalty usually arises as a result of: (i) providing capital in exchange for granting the royalty; or (ii) converting a participating interest in a joint venture relationship into a royalty. Gross overriding royalties are based on the proceeds from the sale of gross production and are free of any operating, capital and environmental costs.

### Description of Royalty Lands

The Corporation's royalty interests represent a geologically and geographically diverse portfolio of properties. The Manager oversees this portfolio through multi-disciplined technical teams, each managing a geographic region.

The following table summarizes, by area, the Corporation's average royalty interest, net reserves, and reserves value as at December 31, 2013, and wells drilled, oil and natural gas production, and royalty revenue for 2013 for the Corporation's Royalty Lands:

Year ended December 31, 2013		Alberta West	Lloydminster	Saskatchewan East	Total
Average royalty interest <sup>(1)</sup>	(%)	1.4	4.3	0.8	1.5
Wells drilled	(gross)	168	74	96	338
Royalty income <sup>(2)</sup>	(\$000s)	49,485	38,210	23,305	111,000
Average net daily production	(boe/d)	3,555	1,763	877	6,195
Oil and NGL	(bbls/d)	1,300	1,512	697	3,509
Natural gas	(Mcf/d)	13,528	1,505	1,082	16,115
Net proved reserves	(Mboe)	6,538	3,305	1,742	11,585
Oil and NGL	(Mbbls)	2,140	2,911	1,235	6,286
Natural gas	(MMcf)	26,389	2,365	3,037	31,792
Net proved plus probable reserves	(Mboe)	9,568	5,330	2,594	17,492
Oil and NGL	(Mbbls)	3,208	4,704	1,837	9,749
Natural gas	(MMcf)	38,164	3,759	4,538	46,461
Future Net Revenue <sup>(1)(2)</sup>					
Discounted at 10% per year	(\$000s)	239,435	195,251	96,882	531,567
	(% of total)	45	37	18	100

(1) Based on proved plus probable reserves and forecast prices as assigned in the Trimble Report.

(2) Excludes income from potash, interest and other.

The following table summarizes, by region, the gross royalty acreage with respect to the Corporation's Royalty Lands by region, as at December 31, 2013:

Area	Developed Gross Acres	Undeveloped Gross Acres <sup>(1)</sup>	Total Gross Acres
Alberta West	1,387,768	335,927	1,723,695
Lloydminster	366,370	109,080	475,450
Saskatchewan East	297,065	328,024	625,089
Potash	15,515	7,351	22,866
Total	2,066,718	780,382	2,847,100

(1) Undeveloped royalty lands are lands without producing or potentially producing wells.

### Alberta West

The Alberta West region includes all of Freehold's royalty interests in British Columbia and Alberta, except for lands in the Lloydminster region. This region contains 61% of Freehold's total royalty acreage, 57% of royalty production, and 55% of net proved plus probable reserves. In 2013, industry operators drilled 168 gross wells on the Royalty Lands in this region. On a boe basis, production increased 5% in 2013 and was 37% oil and NGL and 63%

natural gas. The oil production is 95% light and medium quality crude. The industry continues to utilize horizontal drilling with multistage fracture stimulation to exploit low permeability reservoirs.

Similar to 2012, the Cardium was the primary target for operators on the Royalty Lands in this region in 2013, accounting for approximately 48% of the wells drilled in this region. In addition, increased drilling activity occurred exploiting Viking light oil and liquids rich gas in the Glauconite and Montney Formation.

### ***Lloydminster***

The Lloydminster region encompasses the portions of Alberta and Saskatchewan that extend from Township 31 to Township 65, bounded on the east by Range 13, west of the Third Meridian, and bounded on the west by Range 15, west of the Fourth Meridian. This region contains 17% of Freehold's total royalty acreage, 29% of royalty production, and 30% of net proved plus probable reserves. In 2013, industry operators drilled 74 gross wells on the Royalty Lands in this region. On a boe basis, production decreased 7% in 2013 and was 86% oil and NGL (98% heavy) and 14% natural gas.

The primary target for operators on the Royalty Lands in the Lloydminster region is Mannville Group heavy oil. The oil is exploited with vertical wells using CHOPS (cold heavy oil production with sand) technology or with horizontal wells.

### ***Saskatchewan East***

The Saskatchewan East region includes all of Freehold's royalty interests in Saskatchewan (except for lands in the Lloydminster region) and Manitoba, and minor royalty interests in southern Ontario. This region contains 22% of Freehold's total royalty acreage, 14% of royalty production, and 15% of net proved plus probable reserves. In 2013, industry operators drilled 96 gross wells on the Royalty Lands in this region. On a boe basis, production decreased 12% in 2013 and was 79% oil and NGL and 21% natural gas.

In Saskatchewan and Manitoba, production is almost entirely light to medium oil production recovered primarily from Mississippian subcrop traps and Bakken reservoirs.

### ***Potash***

In 1996, the Corporation acquired the right to the revenue from Canpar's lessor royalty interest in over 9,750 gross acres of leases issued to various operators of seven potash mines, all located within the Province of Saskatchewan. These leases are included within larger potash units, which cover the total mine areas. In 2005, the acquisition of the Partnership resulted in the Corporation increasing its mineral title ownership in six of these mines. As a result, the Corporation's potash acreage inventory increased to approximately 22,900 gross acres.

The potash mines from which the Corporation receives royalties are operated by Potash Corporation of Saskatchewan and The Mosaic Company. In 2013, the Corporation received revenue of approximately \$1.4 million from the production of approximately nine tonnes per day of potash. As the Corporation's minor interests in potash reserves are not material to the Corporation, the Manager has not obtained a recent independent evaluation of the potash reserves.

### ***Undeveloped Royalty Lands***

The undeveloped Royalty Lands are lands without producing or potentially producing wells totalling 780,382 gross acres. Potential exists on these lands for drilling non-unitized zones within producing units, drilling or completing additional zones, infill drilling by downsizing well spacing (e.g. 160 acre to 80 acre spacing in the case of an oil well), optimizing drilling locations within spacing units and horizontal drilling. If a well is drilled on lands adjacent to Royalty Lands where we own the mineral title and that well is producing from a formation in which the Corporation has an interest but that is not producing on the Royalty Lands, the Corporation has the right to require the lessee of the mineral title to either: (a) drill a well on an undrilled spacing unit on the Royalty Lands; (b) pay a compensatory royalty; or (c) surrender the respective formation.

### ***Drilling Activity***

Freehold is not responsible for any drilling or development activity or expenditures with respect to the Royalty Lands leased to third parties, but receives Royalty Income from successful wells. Drilling activity on the Royalty Lands is anticipated to continue to provide new sources of oil and natural gas Royalty Income in future years, with

new wells and production therefrom reducing the rate at which production and Royalty Income would otherwise decline. The extent of drilling and development activity in future years by the operators cannot be predicted.

The following table summarizes the drilling activity conducted by lessees on the Royalty Lands for the two most recently completed fiscal years. During this period, 769 unitized and non-unitized development wells were drilled. No exploratory wells were drilled during this period. The drilling activity on the Royalty Lands in the last two fiscal years may not be indicative of future activity.

The drilling on the Royalty Lands in 2013 included the drilling and completion of 120 unitized and 137 non-unitized horizontal wells compared with 81 unitized and 143 non-unitized horizontal wells in 2012.

Years Ended December 31 <sup>(1)</sup> (gross wells)	2013		2012	
	Unitized	Non-Unitized	Unitized	Non-Unitized
Oil wells	133	141	190	187
Natural gas wells	1	21	4	13
Service/other wells	7	33	6	29
Dry and abandoned wells	-	2	-	2
Total	141	197	200	231
Success rate	100%	99%	100%	99%

(1) Includes all drilling on properties acquired during the year.

**Reconciliation of Royalty Lands Reserves<sup>(2)</sup>**

The following table provides a summary of the changes in the net oil and natural gas reserves on our Royalty Lands during 2013, based on forecast prices and costs:

	Light and Medium Oil			Heavy Oil		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2012	1,977	1,173	3,150	3,485	2,454	5,940
Extensions	189	131	320	48	30	78
Improved recovery	-	-	-	-	-	-
Technical revisions	222	(211)	10	556	(575)	(19)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	82	128	210
Dispositions	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-
Production	(456)	-	(456)	(611)	-	(611)
<b>December 31, 2013<sup>(1)</sup></b>	<b>1,932</b>	<b>1,092</b>	<b>3,024</b>	<b>3,560</b>	<b>2,037</b>	<b>5,597</b>

	Natural Gas			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2012	35,092	17,457	52,549	784	386	1,170
Extensions	268	133	402	10	5	15
Improved recovery	-	-	-	-	-	-
Technical revisions	1,771	(3,018)	(1,247)	170	(58)	113
Discoveries	-	-	-	-	-	-
Acquisitions	278	97	375	-	-	-
Dispositions	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-
Production	(5,618)	-	(5,618)	(169)	-	(169)
<b>December 31, 2013<sup>(1)</sup></b>	<b>31,792</b>	<b>14,669</b>	<b>46,461</b>	<b>795</b>	<b>333</b>	<b>1,128</b>

	Oil Equivalent		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2012	12,095	6,922	19,017
Extensions	291	188	479
Improved recovery	-	-	-
Technical revisions	1,244	(1,348)	(104)
Discoveries	-	-	-
Acquisitions	128	145	273
Dispositions	-	-	-
Economic factors	-	-	-
Production	(2,173)	-	(2,173)
<b>December 31, 2013<sup>(1)</sup></b>	<b>11,585</b>	<b>5,907</b>	<b>17,492</b>

(1) Columns may not add due to rounding.

(2) Excludes minor royalty interests attributable to certain working interest properties.

## Working Interest Properties

The Corporation owns working interests in 108 oil and natural gas properties. Production from these properties is comprised of approximately 81% oil and NGL and 19% natural gas. Working interest production averaged 2,718 boe per day in 2013, up from 2,587 boe per day in 2012. In 2013, 48 (13.6 net) wells were drilled, compared with 37 (14.1 net) wells during 2012.

In 2014, we expect to spend approximately \$35 million on development activities. Development plans are primarily oil related on the Corporation's mineral title lands and include approximately 58 gross (14 net risked) wells. Roughly 40% of our capital will be deployed in Southeast Saskatchewan (light oil), with the balance allocated to our mineral title opportunity base in both the Lloydminster area (heavy oil) and western Alberta (Cardium oil).

Year ended December 31, 2013		Southeast Saskatchewan <sup>(2)(4)</sup>	Other (107 properties) <sup>(2)(4)</sup>	Total <sup>(2)(4)</sup>
Average working interest <sup>(1)</sup>	(%)	22.4	8.4	9.5
Wells drilled	(gross/net)	19/8.4	29/5.2	48/13.6
Net pre-tax operating income <sup>(3)</sup>	(\$000s)	27,085	15,616	42,701
Average gross daily production	(boe/d)	1,163	1,555	2,718
Oil and NGL	(bbls/d)	1,086	1,126	2,212
Natural gas	(Mcf/d)	463	2,570	3,033
Net proved reserves	(Mboe)	414	2,484	2,898
Oil and NGL	(Mbbls)	398	1,925	2,323
Natural gas	(MMcf)	99	3,352	3,451
Net proved plus probable reserves	(Mboe)	1,056	4,565	5,620
Oil and NGL	(Mbbls)	1,011	3,415	4,426
Natural gas	(MMcf)	267	6,900	7,167
Future Net Revenue				
Discounted at 10% per year	(\$000s)	47,740	66,729	114,469
	(% of total)	42	58	100

- (1) The percentage working interest share of reserves and production owned by Freehold in the properties before the deduction of royalties payable to others.
- (2) Excludes royalty interests.
- (3) Excludes income from interest and other.
- (4) Includes non-unit and unit interests.

### Southeast Saskatchewan

In the Southeast Saskatchewan area, we have title interests ranging from 10% to 100%, and working interests ranging from 2.5% to 100%. This region contains 43% of working interest production and 19% of net proved plus probable reserves associated with our working interest properties. Our average working interest is 22.4%, which increased from 18.9% in 2013 due to our drilling program. In 2013, we participated in 19 (8.4 net) wells, primarily on the Corporation's mineral title lands. Capital expenditures totalled approximately \$19 million in 2013 and in 2014, we have allocated about 40% of our capital budget to this area.

In aggregate, from 2005 to 2013, we have participated in 126 (51.7 net) wells in Southeast Saskatchewan. Of these, 60 (29.3 net) were Bakken formation wells and the balance were Mississippian – Frobisher/Alida targets. This participation is the result of the particularly favourable, oil based economics of these opportunities. Approximately 27,000 gross acres of the Corporation's Bakken mineral title lands are unleased.

Production in Southeast Saskatchewan increased 1% in 2013, and was 93% oil and NGL and 7% gas. All of the oil production is of light and medium quality.

The majority of the Corporation's production from the Bakken in Southeast Saskatchewan is processed through facilities where Freehold pays processing fees. The Frobisher/Alida production in Southeast Saskatchewan is processed at non-operated facilities where Freehold has equity ownership interests ranging from 20% to 50%.

### Other Working Interest Properties

We own various working interests in 107 other properties, which accounted for 57% of the working interest production during 2013 and 81% of the net proved plus probable reserves associated with our working interest properties. Individually, each of these properties contributed less than 500 boe per day to production. Capital expenditures totalled approximately \$10 million in 2013, and development activities included the drilling of 29 (5.2 net) wells. Drilling targets included Mannville Group heavy oil, as well as Cardium Viking and Glauconite light oil. Production increased 8% in 2013 and was 72% oil and NGL and 28% natural gas.

In 2014, we have allocated about 60% of our capital budget to various other working interest properties, primarily on our mineral title lands in the Lloydminster area (heavy oil) and west central Alberta (Cardium light oil).

### Working Interest Wells

The following table sets forth the number and status of wells as at December 31, 2013 in which we have a working interest that are producing or considered capable of production:

Property	Producing <sup>(1)</sup>				Non-Producing <sup>(1)(2)(3)</sup>			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Southeast Saskatchewan	205	49.1	-	-	31	3.2	-	-
Other (107 properties)	705	97.3	676	22.6	207	26.8	174	11.3
Total <sup>(4)</sup>	910	146.4	676	22.6	238	30.0	174	11.3

(1) Based on public records.

(2) "Non-producing" wells means wells that are not producing but which are considered capable of production. Non-producing wells in which Freehold has an interest are located no further than ten kilometres from gathering systems, pipeline or other means of transportation.

(3) Not all wells owned by Freehold have been assigned reserves in the Trimble Report.

(4) Columns may not add due to rounding.

### Development Activities

The following table sets forth the development wells in which we participated during the years ended December 31, 2013 and December 31, 2012. No exploratory wells were drilled during this period.

Years Ended December 31	2013		2012	
	Gross	Net	Gross	Net
Wells Drilled				
Oil wells	41	12.9	36	13.5
Natural gas wells	-	-	-	-
Service/other wells	7	0.7	-	-
Dry and abandoned wells	-	-	1	0.6
Total	48	13.6	37	14.1
Success rate	100%		97%	

**Reconciliation of Working Interest Property Reserves<sup>(2)</sup>**

The following tables provide a summary of the changes in the gross oil and natural gas reserves on our working interest properties during 2013, based on forecast prices and costs:

	Light and Medium Oil			Heavy Oil		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2012	1,826	1,346	3,173	856	916	1,771
Extensions	367	304	671	134	65	199
Improved recovery	-	-	-	-	-	-
Technical revisions	184	(190)	(6)	90	(131)	(41)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic factors	7	(4)	2	2	2	3
Production	(558)	-	(558)	(318)	-	(318)
<b>December 31, 2013<sup>(1)</sup></b>	<b>1,827</b>	<b>1,456</b>	<b>3,283</b>	<b>764</b>	<b>851</b>	<b>1,615</b>

	Natural Gas			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2012	4,083	3,042	7,125	154	124	277
Extensions	661	1,693	2,354	48	121	169
Improved recovery	-	-	-	-	-	-
Technical revisions	193	(378)	(186)	13	(7)	6
Discoveries	-	-	-	-	-	-
Acquisitions	87	45	132	-	-	-
Dispositions	-	-	-	-	-	-
Economic factors	(57)	(38)	(95)	(1)	(1)	(2)
Production	(981)	-	(981)	(39)	-	(39)
<b>December 31, 2013<sup>(1)</sup></b>	<b>3,986</b>	<b>4,363</b>	<b>8,349</b>	<b>175</b>	<b>237</b>	<b>412</b>

	Oil Equivalent		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2012	3,516	2,893	6,409
Extensions	659	772	1,432
Improved recovery	-	-	-
Technical revisions	319	(391)	(72)
Discoveries	-	-	-
Acquisitions	14	8	22
Dispositions	-	-	-
Economic factors	(2)	(10)	(12)
Production	(1,077)	-	(1,077)
<b>December 31, 2013<sup>(1)</sup></b>	<b>3,430</b>	<b>3,271</b>	<b>6,702</b>

(1) Columns may not add due to rounding.

(2) The working interest properties include certain minor royalty interests; however, the above table does not reflect such royalty interests because the reconciliation is presented on a gross basis.

## OTHER OIL AND GAS INFORMATION

### Oil and Natural Gas Wells

The following tables set forth, by province, the number and status of wells in which the Corporation has an interest as at December 31, 2013:

Working Interest Properties	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	659	77.6	175	16.0	474	18.7	154	10.0
Saskatchewan	235	67.7	53	13.6	1	-	3	0.8
British Columbia	4	0.2	10	0.3	201	3.8	17	0.5
Manitoba	12	0.9	-	-	-	-	-	-
Total <sup>(1)</sup>	910	146.4	238	30.0	676	22.6	174	11.3

(1) Columns may not add due to rounding.

Royalty Lands <sup>(1)</sup>	Non-Unitized		Unitized	
	Natural Gas Wells	Oil Wells	Natural Gas Wells	Oil Wells
Alberta	5,436	2,785	8,266	5,284
Saskatchewan	1,203	2,076	33	3,682
British Columbia	188	30	1	25
Manitoba	-	28	1	62
Ontario	161	0	-	-
Total <sup>(1)</sup>	6,988	4,919	8,301	9,053

(1) Gross wells in which the Corporation has a royalty interest.

### Properties with No Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2013:

	Undeveloped Acres			
	Royalty Lands		Working Interest Lands	
	Gross	Net	Gross	Net
Alberta	390,976		28,188	5,743
Saskatchewan	24,523		6,131	101
British Columbia	188,881		7,293	4,000
Manitoba	1,422		79	18
Ontario	174,580		-	-
Total	780,382		41,691	9,862

There are no material work commitments on the undeveloped land holdings.

The area of unproved properties for which the Corporation expects its rights to explore, develop, and exploit to expire within the next year, are approximately 3,194 gross acres.

Undeveloped lands are calculated by adding the surface area acreage covered by the leases or agreements or portions of the leases or agreement without producing or potentially producing wells. In certain limited circumstances where we have rights in different formations under the same surface area pursuant to different leases or agreements, we have included the acreage with respect to all such leases or agreements. There are no significant factors or uncertainties associated with the undeveloped land.

### Tax Horizon

The corporate income tax rate applicable to 2013 and 2012 was approximately 25%. Taxable income as a corporation is based on total income and expenses (which will vary depending on commodity prices, production volumes, and costs), reduced by claims for both accumulated tax pools and tax pools associated with current year expenditures. 2012 corporate taxes of \$24 million were paid, \$2 million in 2012 and \$22 million in 2013.

Installments of \$24 million were paid in 2013 for the 2013 tax year, but the 2013 tax bill has not been finalized. We expect our tax bill will normalize in 2014, at approximately 20% of pre-tax cash flow.

### Capital Expenditures

Future capital expenditures are anticipated to be of the types that are intended to maintain or improve production. Freehold may finance capital expenditures from additional issuances of Common Shares, borrowings, farmouts or with working capital. The Corporation did not have any exploration costs related to its activities for the year ended December 31, 2013.

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2013. The acquisition costs were for Royalty Lands and working interest properties. The development costs were on our working interest or unleased mineral title lands.

	(\$000s)
Property acquisition costs <sup>(1)</sup>	
Proved properties	9,176
Undeveloped/unproved properties	915
Development costs	29,287
<b>Total</b>	<b>39,378</b>

(1) As classified at the time of the acquisition.

### Production Estimates

The following table sets out the volume of gross and net production estimated for the year ended December 31, 2014 in the Trimble Report, based on the forecast price case reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data". No fields account for more than 20% of the production estimate.

Reserves Category	Light and Medium Oil		Heavy Oil		Total Crude Oil	
	Gross <sup>(1)</sup>	Net	Gross <sup>(1)</sup>	Net	Gross <sup>(1)</sup>	Net
	(bbls/d)	(bbls/d)	(bbls/d)	(bbls/d)	(bbls/d)	(bbls/d)
Proved						
Developed producing	954	1,731	610	2,007	1,565	3,738
Developed non-producing	42	38	13	10	54	48
Undeveloped	-	-	-	-	-	-
<b>Total proved</b>	<b>996</b>	<b>1,769</b>	<b>623</b>	<b>2,017</b>	<b>1,619</b>	<b>3,786</b>
Probable	295	375	190	252	485	626
<b>Total proved plus probable<sup>(2)</sup></b>	<b>1,291</b>	<b>2,143</b>	<b>813</b>	<b>2,269</b>	<b>2,104</b>	<b>4,412</b>
Reserves Category	Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross <sup>(1)</sup>	Net	Gross <sup>(1)</sup>	Net	Gross <sup>(1)</sup>	Net
	(Mcf/d)	(Mcf/d)	(bbls/d)	(bbls/d)	(boe/d)	(boe/d)
Proved						
Developed producing	1,862	13,980	70	388	1,945	6,456
Developed non-producing	460	420	32	26	163	144
Undeveloped	-	-	-	-	-	-
<b>Total proved</b>	<b>2,321</b>	<b>14,400</b>	<b>102</b>	<b>414</b>	<b>2,107</b>	<b>6,600</b>
Probable	470	952	21	31	584	817
<b>Total proved plus probable<sup>(2)</sup></b>	<b>2,791</b>	<b>15,352</b>	<b>123</b>	<b>445</b>	<b>2,692</b>	<b>7,416</b>

(1) Under NI 51-101, gross production includes only working interests before the deduction of royalties payable and does not include royalties receivable. Net production is comprised of working interests minus royalties payable plus royalties receivable. The Corporation is unique in that the majority of our assets are royalty interests. This causes our gross production to be lower than our net production and may hinder an investor's ability to compare our production with others in our industry.

(2) Columns may not add due to rounding.

## Production History

The following table summarizes our production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	2013				2012			
	Quarter Ended				Quarter Ended			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Average daily production <sup>(1)</sup>								
Light and Medium Oil (bbls/d)	3,180	2,961	2,825	3,132	3,388	3,160	2,605	2,860
Heavy Oil (bbls/d)	2,381	2,287	2,038	2,341	2,363	2,159	2,354	2,242
Natural Gas (Mcf/d)	19,368	18,046	20,411	18,773	20,420	17,110	18,642	19,541
NGL (bbls/d)	384	443	449	465	355	483	435	374
Combined (boe/d)	9,173	8,699	8,714	9,067	9,510	8,654	8,501	8,733
Average price realized								
Light and Medium Oil (\$/bbl)	82.41	99.66	88.42	81.85	80.12	80.09	77.24	87.84
Heavy Oil (\$/bbl)	60.88	86.40	69.45	49.89	61.33	63.59	60.42	73.34
Natural Gas (\$/Mcf)	2.72	2.08	2.92	2.41	2.56	1.73	1.15	2.06
NGL (\$/bbl)	68.60	54.67	56.41	57.55	60.92	56.96	55.27	60.40
Combined (\$/boe)	52.99	63.74	54.66	49.09	51.55	51.71	45.74	54.80
Royalty expense <sup>(2)</sup>								
Light and Medium Oil (\$/bbl)	4.78	4.56	4.23	2.76	4.94	3.45	5.09	2.74
Heavy Oil (\$/bbl)	1.39	1.90	1.13	2.06	1.48	2.10	1.52	2.19
Natural Gas (\$/Mcf)	-	0.05	0.02	0.01	-	(0.01)	0.03	0.01
NGL (\$/bbl)	4.07	2.21	1.79	1.96	2.70	2.48	1.87	4.12
Combined (\$/boe)	2.19	2.27	1.77	1.60	2.24	1.91	2.15	1.67
Operating expenses (\$/boe) <sup>(3)</sup>								
Light and Medium Oil (\$/bbl)	8.49	8.43	8.25	7.31	7.98	7.09	6.05	7.84
Heavy Oil (\$/bbl)	10.52	10.79	12.83	6.83	8.57	7.58	5.51	6.86
Natural Gas (\$/Mcf)	0.34	0.25	0.14	0.23	0.22	0.23	0.21	0.13
NGL (\$/bbl)	2.65	2.42	1.29	2.15	1.97	1.57	2.16	1.35
Combined (\$/boe)	6.50	6.36	6.06	4.88	5.51	5.02	3.96	4.68
Netback received <sup>(4)</sup>								
Light and Medium Oil (\$/bbl)	69.14	86.67	75.94	71.78	67.20	69.55	66.10	77.26
Heavy Oil (\$/bbl)	48.97	73.71	55.49	41.00	51.28	53.91	53.39	64.29
Natural Gas (\$/Mcf)	2.38	1.78	2.76	2.17	2.34	1.51	0.91	1.92
NGL (\$/bbl)	61.88	50.04	53.33	53.44	56.27	52.91	51.24	54.95
Combined (\$/boe)	44.30	55.11	46.83	42.61	43.80	44.78	39.63	48.45

(1) Calculated by adding Net production from our Royalty Lands and Gross production from our working interest properties (except certain royalty interests owned by Freehold associated with the working interest properties have been deducted from the Gross production of the working interest properties as such production is reflected in the Net production from the Royalty Lands in the above table).

(2) Royalty expense includes all Crown charges and royalty payments to third parties.

(3) Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas and natural gas liquids production. Overhead recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.

(4) Netbacks are calculated by subtracting royalty expenses and operating costs from revenues.

(5) Excludes income from potash, interest and other.

The following table summarizes our average daily production from important regions or fields for the year ended December 31, 2013:

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (boe/d)
Royalty Lands <sup>(1)</sup>					
Alberta West	930	53	13,528	317	3,555
Lloydminster	34	1,476	1,505	2	1,763
Saskatchewan East	683	1	1,082	13	877
Working Interest Properties <sup>(2)</sup>					
Southeast Saskatchewan	1,042	-	463	44	1,163
Other (107 properties)	335	732	2,570	59	1,555
<b>Total</b>	<b>3,024</b>	<b>2,262</b>	<b>19,148</b>	<b>435</b>	<b>8,913</b>

(1) Production from the Royalty Lands is presented on a Net basis.

(2) Production from our working interest properties is presented on a Gross basis (except certain royalty interests owned by Freehold associated with the working interest properties have been deducted from the Gross production as such production is reflected in the Net production from the Royalty Lands in the above table).

### Environmental Obligations

Freehold is primarily a royalty company and has no employees. Most of the oil and gas properties in which Freehold has royalty interests are operated by other companies, and Freehold has little power to influence the operations of those properties. While environment, health and safety, and other risks arising out of these operations are not typically direct risks for Freehold, our business model is dependent on the industry operating in a responsible manner.

Almost 80% of Freehold's royalty revenue comes from 30 oil and gas companies. The majority of these companies are large Canadian producers that are members of the Canadian Association of Petroleum Producers (CAPP) and align their operations with industry best practices. Operating members of CAPP are required to participate in CAPP's Responsible Canadian Energy™ program. The program represents a collective commitment to measure industry performance and to encourage members to find new approaches to reduce their environmental footprint, to ensure every worker returns home safely every day, and to continue to improve the ways we communicate and engage the public and other stakeholders.

### Additional Information Concerning Abandonment and Reclamation Costs

We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of our working interest properties upon abandonment. We have no reclamation responsibilities on our Royalty Lands as these are the responsibility of the working interest owners. Ongoing environmental obligations are funded from funds from operations. At December 31, 2013, our estimated undiscounted share of future environmental and reclamation obligations for the working interest properties was approximately \$30.3 million.

Future abandonment and reclamation costs have been estimated based on actual costs incurred to date for abandonment and reclamation activities. In the future, we expect to abandon and reclaim approximately 250 net wells at the estimated costs identified in the following table:

As at December 31, 2013	Abandonment and Reclamation Costs (Net of Salvage Value) (\$000s)	
	Undiscounted	Discounted at 10%
Total costs as at December 31, 2013	30,274	6,969
Total costs not deducted from future net revenue	19,133	3,170
Expected to be paid in 2014	80	77
Expected to be paid in 2015	1,556	1,349
Expected to be paid in 2016	77	61

## BORROWINGS

Freehold has a \$195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks and a \$15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees. The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. As at December 31, 2013, we had \$161 million of available capacity under our credit facilities.

Freehold's borrowing base is dependent on our lenders' annual review and interpretation of our reserves and future commodity prices. This review was completed in the second quarter of 2013 with no changes to our borrowing base. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice.

Under our credit facilities, we are restricted from making dividends if we are or would be in default under the facilities or if our borrowings thereunder exceed our borrowing base. As at December 31, 2013, Freehold was in compliance with all such covenants.

## 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 and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, Saskatchewan and Manitoba, 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 Corporation 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*

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional markets 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* which received Royal Assent on June 29, 2012 (the "**Prosperity Act**"). 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*".

#### *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 be influenced by supply and demand fundamentals or 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<sup>3</sup>/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 which 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%

Oil sands projects are also subject to Alberta’s royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil and Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to \$55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at \$120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above \$55 up to 40% when oil is priced at \$120 or higher. In addition, concurrent with the implementation of The New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the new royalty regime.

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 which 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 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 on 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 on 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.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice if it decides to discontinue the program.

### **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 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 the 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%.

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 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 and is intended to reflect the higher drilling and completion costs;
- *Deep Re-Entry Royalty Credit Program* providing royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that 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<sup>3</sup> 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<sup>3</sup> 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<sup>3</sup> 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<sup>3</sup>;
- *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<sup>3</sup> per

metre of depth for exploratory wildcat wells and less than 11 m<sup>3</sup> 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<sup>3</sup>; 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<sup>3</sup> of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program which 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 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month.

### **Saskatchewan**

In Saskatchewan, the amount payable as Crown royalty or 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 conventional royalty and production tax classifications (“fourth tier oil”, “third tier oil”, “new oil” and “old oil”) depend on the finished drilling date of a well and are 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<sup>3</sup> for “old oil”, “new oil” and “third tier oil”, and 250 m<sup>3</sup> per month for “fourth tier oil”. Where average wellhead prices are below the established base prices of \$100 per m<sup>3</sup> for third and fourth tier oil and \$50 per m<sup>3</sup> 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 Crown royalty or 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<sup>3</sup> of gas for every m<sup>3</sup> 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<sup>3</sup> m<sup>3</sup>/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<sup>3</sup> for deep development vertical oil wells, 4,000 m<sup>3</sup> for non-deep exploratory vertical oil wells and 16,000 m<sup>3</sup> 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<sup>3</sup> 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<sup>3</sup> for non-deep horizontal oil wells and 16,000 m<sup>3</sup> 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<sup>3</sup> 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 enhanced oil recovery 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 (SRC) 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. These will apply to existing licensed wells and facilities on July 1, 2015.

### **Manitoba**

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

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

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

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

Wells drilled or receiving a marginal well major workover incentive after December 31, 2013 and prior to January 1, 2019 must pay a minimum royalty on Crown production or a minimum tax on freehold production.

Wells drilled for injection, or converted to injection wells, in an approved enhanced recovery project, earn a one (1) year holiday for portions of the project area.

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

- *Vertical Well Incentive* provides licensees of a vertical development or exploratory well drilled after December 31, 2013 and prior to January 1, 2019 with a holiday oil volume (a “HOV”) of 500 m<sup>3</sup>. To qualify, the well must be less than 1.6 kilometres from the nearest well cased for production from the same or deeper zone;
- *Exploration and Deep Well Incentive* provides a HOV for exploratory or deep oil development wells drilled after December 31, 2013 and prior to January 1, 2019 as follows:
  - Non-deep exploratory wells drilled more than 1.6 kilometres from the nearest well cased for production from the same or deeper zone earn a HOV of 4,000 m<sup>3</sup>;
  - Deep exploratory wells drilled below the Birdbear formation earn a HOV of 8,000 m<sup>3</sup>; and
  - Deep development wells completed for production in the Birdbear formation or deeper earn a HOV of 8,000 m<sup>3</sup>;
- *Horizontal Well Incentive* provides a HOV of 8,000 m<sup>3</sup> for any horizontal well drilled after December 31, 2013 and prior to January 1, 2019 achieving an angle of at least 80 degrees for a minimum distance of 100 metres;
- *Marginal Well Major Workover Incentive* provides a HOV of 500 m<sup>3</sup> for any marginal well where a major workover is completed prior to January 1, 2019. A marginal oil well is a well or abandoned well that was not operated over the previous 12 months or that produced at an average rate of less than 3 m<sup>3</sup> per operating day;
- *Pressure Maintenance Project Incentive* provides a one-year exemption from the payment of Crown royalties or freehold production taxes for a unit tract in which an injection well is drilled or a well is converted to water injection. For a well that is converted to injection after December 31, 2013 and before January 21, 2019 and that has remaining HOV, the exemption will be extended to 18 months; and
- *Solution Gas Conservation Incentive* provides a royalty and tax exemption on gas until December 31, 2018 for projects that capture solution gas implemented after December 31, 2013.

The Holiday Oil Volume Account, which allowed the movement of HOV to and from wells under specific conditions will be eliminated as of January 1, 2015. Until December 31, 2014, the holder of an existing account may make a one-time transfer of 2,000 m<sup>3</sup> to a well drilled between January 1 and December 31, 2014.

## Land Tenure

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

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or 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.

## 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 30, 2014, the AER is expected to assume 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 oilsands area, which contains approximately 82% of the province’s oilsands resources and much of the Cold Lake oilsands 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, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands 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.

The next regional plan to take effect is the South Saskatchewan Regional Plan (“SSRP”) which covers approximately 83,764 square kilometres and includes 45% of the provincial population. The SSRP was released in draft form in 2013 and is expected to come into force on April 1, 2014.

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 British Columbia. 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* 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 of 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 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.

### **Manitoba**

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

## **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).

The changes will be implemented over a three-year period, ending May 2015. The changes to the AB LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

### **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.

### **Manitoba**

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

## Climate Change Regulation

### **Federal**

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 GHG 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, 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 greenhouse gas 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 GHG 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 baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year and 10% of 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<sub>2</sub> 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<sub>2</sub> 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 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 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*, under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the greenhouse gas 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 further 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. The MRGGA and related regulations have yet to be proclaimed in force.

### **Manitoba**

The Government of Manitoba commenced public consultations with respect to the development of a cap and trade system to reduce GHG emissions in 2010. The enactment of *The Climate Change and Emissions Reductions Act* (Manitoba) set emission reduction targets as of December 31, 2012 at 6% below 1990 emissions and details the

commitment of the Government of Manitoba to various initiatives in an effort to reduce greenhouse gas emissions. However, no legislation has been enacted which imposes mandatory emission reduction targets on emitters.

## RISK FACTORS

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

### Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas produced from properties in which the Corporation has an interest. The ability of the Corporation or the operators of properties in which the Corporation has an interest to market their oil and natural gas may depend upon the 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 Corporation'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 Corporation.

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 Corporation. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation'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 Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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.

### 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 Corporation depends on its ability to find and acquire royalty and working interests in oil and natural gas properties and for the operators of such properties to successfully develop and commercially produce oil and natural gas reserves from such properties. Without the continual addition of new royalty interests or reserves from existing royalty interests, the Corporation's existing reserves, and the production from them, will decline over time as such reserves are produced. A future increase in the Corporation's reserves will depend on both the successful exploration and development of its royalty and working interest properties and on its ability to select and acquire royalty and working interests in suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find

satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will acquire further royalty or working interests or that additional commercial quantities of oil and natural gas will be discovered and produced on the oil and natural gas properties in which the Corporation currently has a royalty or working interest.

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 Corporation 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 Corporation.

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 Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance 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 Corporation could incur significant costs.

### **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 Corporation'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 Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares of the Corporation will trade cannot be accurately predicted.

### **Failure to Realize Anticipated Benefits of Acquisitions and Dispositions**

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses 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 Corporation 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 Corporation, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

## Operational Dependence

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

## Project Risks

The Corporation 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 Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation'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 Corporation'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;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation 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 Corporation 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 Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of 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 Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation'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 Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

Following major accidents in Lac-Mégantic, 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 Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale.

### **Competition**

The petroleum industry is competitive in all its phases. The Corporation 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 Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, 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 Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be affected adversely and materially. If the Corporation 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 Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

### **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 Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation'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 Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

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

## 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 Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental 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 Corporation'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 Corporation's 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.

## Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation 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 Corporation'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 Corporation'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 Corporation 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 Corporation's production revenues. Accordingly, Canadian/United States exchange rates could affect the future value of the Corporation's reserves as determined by independent evaluators.

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

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

### **Substantial Capital Requirements**

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

- the overall state of the capital markets;
- the Corporation's credit rating (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 Corporation's securities in particular.

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

### **Additional Funding Requirements**

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

Because of global economic volatility, the Corporation 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 Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable, or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon

acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

### **Global Financial Markets**

Global and regional financial market events and conditions, including disruptions in the international credit markets and other financial systems can cause significant volatility in commodity prices. These events and conditions may cause a decrease in confidence in global credit and financial markets and may create a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Such circumstances may result in concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions and cause the broader credit markets to deteriorate and stock markets to decline substantially. These factors may negatively impact company valuations. Petroleum prices often experience volatility as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by the Organization of the Petroleum Exporting Countries ("OPEC") and the global credit and liquidity concerns. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

### **Credit Facility Arrangements**

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

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

### **Issuance of Debt**

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

### **Hedging**

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to

manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- 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.

In addition, the Corporation may enter into agreements to fix the price paid for electricity used in its operations to offset the risk of increased operating costs if the price of electricity increases. However, to the extent that the Corporation engages in price risk management activities to protect itself from increases in electricity prices, it may also be prevented from realizing the full benefits of price decreases below the levels of the derivative instruments used to manage price risk.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, the Corporation 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 Corporation and may delay exploration and development activities.

### **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 Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

### **Reserve Estimates**

There are numerous uncertainties inherent in estimating quantities of oil, natural gas, natural gas liquids, and sulphur 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 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; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof 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 Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

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

## **Insurance**

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

## **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 Corporation. 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 Corporation's net production revenue.

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

## **Dilution**

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

## **Management of Growth**

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

## **Expiration of Licences and Leases**

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

## **Dividends**

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

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

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

## **Litigation**

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, 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 Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

## **Aboriginal Claims**

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful, such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

### **Breach of Confidentiality**

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

### **Income Taxes**

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

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

In addition, as set out herein the Corporation has certain expectations as to the level of corporate income tax paid or to be paid for the previous year, the current year and future years. To the extent that such corporate income tax levels are higher than anticipated it could have an impact on the Corporation's ability to fund its operations and capital expenditures and may also impact the amount or payment of dividends by the Corporation.

### **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 Corporation.

### **Third Party Credit Risk**

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

### **Conflicts of Interest**

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation 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.

In addition, there may be circumstances in which the interests of the Manager will conflict with those of the Shareholders as the Manager provides similar management services to Canpar and Rife and may provide similar management services to others in the future. The Manager may acquire oil and gas properties on its own behalf or on behalf of persons other than Freehold. The Manager may manage and administer such additional properties, as well as enter into other types of energy-related management and advisory activities.

The Manager will use all reasonable efforts to resolve any conflicts of interest that arise in a manner which will treat Freehold and the other interested parties fairly, taking into account all of the circumstances of Freehold and such interested parties and will act honestly and in good faith in resolving such matters; however, as a result of such conflicts of interest the Corporation may not be able to take advantage of certain opportunities and such conflicts may not always be resolved in a manner favourable to Freehold.

See “Directors and Officers – Conflicts of Interest” and “The Manager – Management Agreement”.

### **Reliance on Key Personnel**

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

### **Expansion into New Activities**

The operations and expertise of the Corporation’s management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future the Corporation 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 Corporation’s exposure to one or more existing risk factors, which may in turn result in the Corporation’s future operational and financial conditions being adversely affected.

## **DESCRIPTION OF CAPITAL STRUCTURE**

The authorized capital of Freehold consists of an unlimited number of Common Shares and 10,000,000 Preferred Shares. As of the date hereof, there are 68,021,670 Common Shares and no Preferred Shares issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions which are attached to the Common Shares and Preferred Shares.

### **Common Shares**

Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Freehold. Subject to the prior satisfaction of all preferential rights attached to other classes of shares of Freehold, the holders of Common Shares are entitled to receive dividends if, as and when declared by the Board of Directors and to receive pro rata the remaining property and assets of Freehold upon its dissolution or winding-up.

### **Preferred Shares**

The Preferred Shares are issuable in one or more series and the Board of Directors may fix their issue, the number of shares of each series and the designation, rights, privileges, restrictions and conditions attached to each series of Preferred Shares. The Preferred Shares of each series shall, with respect to the payment of dividends and the distribution of assets or the return of capital in the event of the liquidation, dissolution or winding-up of Freehold, rank on a parity with the Preferred Shares of every other series and are entitled to a preference over the Common Shares and any other shares of Freehold ranking junior to the Preferred Shares.

Other than in the case of a failure to declare or pay dividends specified in any series of the Preferred Share, the voting rights attached to the Preferred Shares shall be limited to one vote per Preferred Share at any meeting where the Preferred Shares, if any, and Common Shares vote together as a single class.

## MARKET FOR SECURITIES

### Common Shares

The Common Shares are listed and trade on the TSX under the symbol “FRU”. The following table sets forth the high and low trading prices and the aggregate trading volume of the Common Shares for the periods indicated:

<b>TORONTO STOCK EXCHANGE COMMON SHARES TRADING RANGE</b>				
(Cdn\$ per Common Share)				
	High	Low	Close	Volume Traded
<b>2013</b>				
January	24.48	21.97	23.10	2,398,141
February	23.68	21.00	21.51	2,440,239
March	23.63	21.21	23.38	2,364,235
April	24.58	22.46	24.52	2,781,002
May	24.47	23.09	23.83	2,970,364
June	24.36	22.76	23.57	2,356,562
July	24.88	23.36	23.61	1,361,324
August	24.06	22.50	23.65	1,383,969
September	24.19	22.91	23.78	1,628,623
October	24.63	23.31	23.73	1,909,471
November	23.70	22.12	22.57	2,079,649
December	22.71	21.54	22.11	2,088,105
<b>2014</b>				
January	23.02	21.55	22.34	3,066,123
February	22.90	21.41	22.67	2,324,429
March 1 to 5	22.82	22.46	22.74	105,809

## ESCROWED SECURITIES

To the knowledge of the Corporation, no securities of the Corporation are held in escrow.

## DIVIDENDS

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at December 31, 2013, our legal stated capital was \$421 million.

Monthly dividends of Freehold are currently declared for Shareholders of record as of the last day of each month and are paid on or about the 15<sup>th</sup> day of the following month. The dividends are “eligible dividends” for income tax purposes and thus qualify for the enhanced gross-up and tax credit regime available to certain holders of Common Shares. The amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, participation levels in the DRIP, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, income taxes and the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends.

The Board of Directors reviews the dividend policy quarterly and at its discretion, any excess income available for dividends may be directed toward repayment of long-term debt and improvements in working capital.

### Record of Cash Dividends

Since January 1, 2014, Freehold has declared cash dividends of \$0.14 per Common Share for Shareholders of record on January 31, 2014, February 28, 2014, and March 31, 2014, payable on February 17, 2014, March 17, 2014, and April 15, 2014, respectively.

The tables below set forth the amount of cash dividends paid on the Common Shares during the three most recently completed financial years:

Record Date	Payment Date	Cdn\$ per Share
<b>2011</b>		
January 31, 2011	February 15, 2011	0.14
February 28, 2011	March 15, 2011	0.14
March 31, 2011	April 15, 2011	0.14
April 30, 2011	May 16, 2011	0.14
May 31, 2011	June 15, 2011	0.14
June 30, 2011	July 15, 2011	0.14
July 31, 2011	August 15, 2011	0.14
August 31, 2011	September 15, 2011	0.14
September 30, 2011	October 17, 2011	0.14
October 31, 2011	November 15, 2011	0.14
November 30, 2011	December 15, 2011	0.14
December 31, 2011	January 16, 2012	0.14
		1.68
<b>2012</b>		
January 31, 2012	February 15, 2012	0.14
February 29, 2012	March 15, 2012	0.14
March 31, 2012	April 16, 2012	0.14
April 30, 2012	May 15, 2012	0.14
May 31, 2012	June 15, 2012	0.14
June 30, 2012	July 16, 2012	0.14
July 31, 2012	August 15, 2012	0.14
August 31, 2012	September 17, 2012	0.14
September 30, 2012	October 15, 2012	0.14
October 31, 2012	November 15, 2012	0.14
November 30, 2012	December 17, 2012	0.14
December 31, 2012	January 15, 2013	0.14
		1.68
<b>2013</b>		
January 31, 2013	February 15, 2013	0.14
February 28, 2013	March 15, 2013	0.14
March 31, 2013	April 15, 2013	0.14
April 30, 2013	May 15, 2013	0.14
May 31, 2013	June 17, 2013	0.14
June 30, 2013	July 15, 2013	0.14
July 31, 2013	August 15, 2013	0.14
August 31, 2013	September 16, 2013	0.14
September 30, 2013	October 15, 2013	0.14
October 31, 2013	November 15, 2013	0.14
November 30, 2013	December 16, 2013	0.14
December 31, 2013	January 15, 2014	0.14
		1.68

### **Passive Foreign Investment Company**

In consultation with its U.S. tax advisors, Freehold believes it should be classified as a passive foreign investment company (“PFIC”) under United States federal income tax principles. As such, dividends to taxable individual Shareholders who are United States taxpayers should continue to be subject to the regimes of United States federal income taxation applicable to PFICs. Shareholders who are United States taxpayers should discuss with their tax advisors the reporting requirements with respect to owning shares in a PFIC. Freehold, in order to allow Shareholders the ability to make a Qualified Electing Fund election, posts annually a PFIC Annual Information Statement on its website. Shareholders should contact their own tax advisors for information on correctly completing Form 8621. This information is not available from Freehold.

### **Direct Deposit Plan**

A direct deposit plan has been established for the Corporation to provide holders who have Canadian bank accounts with a method of receiving cash dividends as a direct deposit into their bank account.

### **Dividend Reinvestment Plan**

The purpose of the DRIP is to provide Shareholders who are residents of Canada (within the meaning of the Tax Act) with a method of reinvesting cash dividends into new Common Shares.

Under the DRIP, we are currently issuing Common Shares from treasury instead of purchasing them in the market.

Effective with the May 15, 2011 dividend payment, the DRIP was amended and restated to allow for the issuance of shares from treasury at a 5% discount to market (i.e. 95% of the weighted average closing price for the ten trading days preceding each payment date).

### **U.S. Currency Payment Plan**

The U.S. currency payment plan allows holders of Common Shares of the Corporation who maintain U.S. currency accounts to obtain payments in U.S. currency.

## **CORPORATE GOVERNANCE**

### **General**

Subject to the ultimate authority of the Board of Directors, Freehold, Freehold Resources and the Partnership are managed by the Manager.

### **Governance Agreement**

The Governance Agreement provides that if the Manager and its affiliates, including the CN Pension Trust Funds, hold 10% or more of the issued and outstanding Common Shares, the Manager will have the right to nominate for election two individuals as directors of Freehold. If the Manager and its affiliates hold less than 10% of the issued and outstanding Common Shares, the Manager will have the right to nominate for election one individual as a director of Freehold. If the individuals nominated by the Manager fail to get elected or if the Manager ceases to hold any Common Shares (in which case the Manager will not have the right to nominate any individuals as directors of Freehold) but continues to act as manager of Freehold pursuant to the Management Agreement, the Governance Agreement will provide the Manager with the right to have an observer present at all meetings of directors of Freehold. The CN Pension Trust Funds holds, directly or indirectly, approximately 27% of the outstanding Common Shares and as a result, has the right to nominate two individuals as directors of Freehold.

### **Decision Making**

Although the Manager provides certain advisory and management services to Freehold pursuant to the Management Agreement, the Board of Directors supervises the management of the business and affairs of Freehold. In particular, significant operational decisions and all decisions relating to: (a) issuances of additional securities of Freehold; (b) the acquisition and disposition of properties of Freehold, and its subsidiaries and partnerships for a purchase price or proceeds in excess of \$10 million; (c) capital expenditures outside of approved budgets; (d) establishment of credit facilities and hedging; and (e) the payment of dividends to Shareholders of Freehold, are made by the Board of

Directors. Any amendment to the Management Agreement requires the approval of the Board of Directors. The Board of Directors hold regularly scheduled meetings to review the business and affairs of Freehold and make any necessary decisions relating thereto.

### Board of Directors of Freehold

As at March 6, 2014, the Board of Directors was comprised of eight individuals. The name, province of residence, position held and principal occupation of each director of Freehold are set out below:

<b>Name and Province of Residence</b>	<b>Position with Freehold</b>	<b>Principal Occupation</b>	<b>Director Since</b>
D. Nolan Blades <sup>(3)</sup> Alberta, Canada	Chair of the Board and Director	President, Sunny Gables Holdings Ltd. (private holding company)	July 29, 1996 <sup>(6)</sup>
Harry S. Campbell, Q.C. <sup>(3)(4)</sup> Alberta, Canada	Director	Chairman, Burnet, Duckworth & Palmer LLP (barristers and solicitors)	July 29, 1996 <sup>(6)</sup>
Peter T. Harrison <sup>(4)(5)</sup> Quebec, Canada	Director	Manager, Oil and Gas Investments CN Investment Division	July 29, 1996 <sup>(6)</sup>
Arthur N. Korpach <sup>(1)(2)</sup> Alberta, Canada	Director	Corporate Director	May 9, 2012
Thomas J. Mullane <sup>(5)</sup> Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer, Rife (private oil and gas exploration and production company)	May 15, 2013
David J. Sandmeyer <sup>(2)(4)</sup> Alberta, Canada	Director	Corporate Director	July 29, 1996 <sup>(6)</sup>
Rodger A. Tourigny <sup>(1)(2)</sup> Alberta, Canada	Director	President, Tourigny Management Ltd. (private consulting company)	November 10, 2009 <sup>(6)</sup>
Aidan M. Walsh <sup>(1)(3)</sup> Alberta, Canada	Director	President and Chief Executive Officer of Baccalieu Energy Inc. (a private oil and gas exploration and production company)	May 15, 2013

(1) Member of Audit Committee.

(2) Member of Compensation Committee.

(3) Member of Governance and Nominating Committee.

(4) Member of Reserves Committee.

(5) Directors nominated for election at the last annual meeting of Shareholders held on May 15, 2013 by the Manager pursuant to the Governance Agreement.

(6) Reflects the date of election or appointment as a member of the board of directors of Freehold Resources Ltd. prior to completion of the plan of arrangement on January 1, 2011 that resulted in Freehold, directly or indirectly, acquiring all of the assets and assuming all of the liabilities of Freehold Royalty Trust.

## Officers of Freehold

The following table sets forth the name, province of residence, position held and principal occupation of each of the officers of Freehold:

<b>Name and Province of Residence</b>	<b>Position with Freehold</b>	<b>Principal Occupation</b>	<b>Officer Since</b>
Thomas J. Mullane Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer of Rife	July 18, 2012
Darren G. Gunderson Alberta, Canada	Vice-President, Finance and Chief Financial Officer	Vice-President, Finance and Chief Financial Officer of Rife	November 13, 2003 <sup>(1)</sup>
Garry W. Bieber Alberta, Canada	Vice-President, Special Projects	Vice-President, Special Projects of Rife	August 13, 2008 <sup>(1)</sup>
Scott W. Hadley Alberta, Canada	Vice-President, Exploration	Vice-President, Exploration of Rife	June 3, 2013
Daniel R. Moore Alberta, Canada	Vice-President, Production	Vice-President, Production of Rife	January 1, 2014
Michael J. Stone Alberta, Canada	Vice-President, Land	Vice-President, Land of Rife	March 1, 2010 <sup>(1)</sup>
Michael J. Mogan Alberta, Canada	Controller	Controller of Freehold	August 13, 2008 <sup>(1)</sup>
Karen C. Taylor Alberta, Canada	Corporate Secretary	Corporate Secretary of Rife	February 27, 2008 <sup>(1)</sup>

(1) Reflects the date of appointment as an officer of Freehold Resources Ltd. prior to completion of the plan of arrangement on January 1, 2011 that resulted in Freehold, directly or indirectly, acquiring all of the assets and assuming all of the liabilities of Freehold Royalty Trust.

Each of the directors and officers of Freehold has been engaged in his or her principal occupation or in other capacities with the same firm or organization for the past five years except for Mr. Hadley, who prior to joining Rife in 2013 was Vice-President, Exploration of Santonia Energy Ltd., Mr. Mullane, who prior to joining Rife in 2012 was Senior Vice President of Bonavista Energy Corporation, Mr. Korpach, who prior to May 31, 2012 was Vice-Chairman, Investment Banking at CIBC World Markets Inc., Mr. Moore, who prior to joining Rife in 2011 was Vice-President, Engineering of Stetson Oil and Gas Ltd., Mr. Harrison, who prior to joining the CN Investment Division on August 24, 2009 was Senior Vice-President of Montrusco Bolton Investments Inc., and Mr. Sandmeyer, who retired as President and Chief Executive Officer of Freehold Resources, Rife and Canpar on May 13, 2009.

As at March 6, 2014, the directors and senior officers of Freehold, as a group, beneficially owned or controlled, directly or indirectly, 106,573 Common Shares or less than 1% of the issued and outstanding Common Shares. CN Pension Trust Funds, owned, directly or indirectly, 18,412,957 Common Shares (approximately 27%) of the Corporation as at March 6, 2014. The Manager has received 2,111,544 Common Shares in payment of the Management Fee to March 6, 2014.

The following is a brief description of the backgrounds of the directors and officers of Freehold.

***D. Nolan Blades***

Mr. Blades is President of Sunny Gables Holdings Ltd. (Calgary), a private investment company. Mr. Blades has obtained significant financial experience and exposure to accounting, financial and compensation issues as President and Chief Executive Officer of Pursuit Resources Corp. (1993 – 2000), prior to which he held senior executive positions with Chauvco Resources Ltd. and Oakwood Petroleum Limited. Mr. Blades has a Bachelor of Science degree in Mechanical Engineering and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

***Harry S. Campbell, Q.C.***

Mr. Campbell is Chairman of the law firm Burnet, Duckworth & Palmer LLP (Calgary). He was admitted to the Alberta Bar in 1974 and has extensive experience with Canadian oil and gas transactions and international petroleum and natural gas matters. Mr. Campbell is a director of Delphi Energy Corp.

***Peter T. Harrison***

Mr. Harrison is Manager, Oil and Gas Investments of the CN Investment Division (Montreal), which manages one of the largest corporate pension funds in Canada. Prior to joining the CN Investment Division in August 2009, he was Senior Vice-President of Montrusco Bolton Investments Inc. (Montreal). He has a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario, and is a Chartered Financial Analyst. Mr. Harrison is a director of Spyglass Resources Corp.

***Arthur N. Korpach***

Mr. Korpach is a corporate director and past Vice-Chairman Investment Banking at CIBC World Markets Inc. (Calgary). He is a Fellow Chartered Accountant and a Chartered Business Valuator with 27 years of investment banking experience. He has a Bachelor of Commerce degree from the University of Saskatchewan and an MBA from Harvard Business School. Mr. Korpach is a director of Canadian Oil Sands Limited and Canexus Corporation. He is a director of the Heart and Stroke Foundation Alberta, a director and past Chair of the board of directors of the United Way of Calgary and Area, past Chair of the Accounting Standards Board of the Canadian Institute of Chartered Accountants, and past director of Mount Royal University and its Foundation.

***Thomas J. Mullane***

Mr. Mullane is the President and Chief Executive Officer of the Corporation. He joined Rife as Executive Vice-President and Chief Operating Officer on July 18, 2012 and was appointed President and Chief Executive Officer on May 17, 2013. He has over 25 years of industry experience and a broad background in exploitation and production engineering gathered from both domestic and international assignments. Prior to joining Rife, Mr. Mullane most recently served as Senior Vice-President of Bonavista Energy Corporation. Over his 12 years at Bonavista, his responsibilities included acquisitions and divestitures, exploitation and reservoir engineering management. He graduated from the University of Alberta in 1983 with a Bachelor of Science degree in Chemical Engineering and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

***David. J. Sandmeyer***

Mr. Sandmeyer is a retired businessman and was formerly President and Chief Executive Officer of Freehold Resources and Rife until his retirement on May 13, 2009. Prior to joining Rife in 1982, he held senior positions with Amoco Canada Petroleum Company Ltd. A graduate of the University of Saskatchewan, he has a Bachelor of Science degree in Mechanical Engineering and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Mr. Sandmeyer is Chair of Anderson Energy Ltd. and a director of Delphi Energy Corp.

**Rodger A. Tourigny**

Mr. Tourigny is President of Tourigny Management Ltd. (Calgary), a private consulting company providing services to the oil and gas, financial services and real estate sectors since 1979. He has extensive financial experience in the oil and gas industry. He has a Bachelor of Commerce degree from the University of Saskatchewan and is a Chartered Accountant. Mr. Tourigny is a director of Bonterra Energy Corp. and LED Medical Diagnostics Inc.

**Aidan M. Walsh**

Mr. Walsh is President and Chief Executive Officer of Baccalieu Energy Inc. (Calgary), a private junior oil and gas company that he co-founded in 2008. He was President and Chief Executive Officer of Burmis Energy Inc. from 2003 to 2008, and President and Chief Executive Officer of Elk Point Resources Inc. from 1993 to 2003. He is currently a director and former Chair of the Explorers and Producers Association of Canada (EPAC). Mr. Walsh has a Bachelor of Engineering degree in Mechanical Engineering from Memorial University of Newfoundland and an MBA from the University of Calgary. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

**Darren G. Gunderson**

Mr. Gunderson is Vice-President, Finance and Chief Financial Officer of the Corporation and was appointed Vice-President, Finance and Chief Financial Officer of Freehold Resources and Rife on August 13, 2008. He joined Rife in 1991 in the accounting department and became Controller in 1999. Mr. Gunderson has a Bachelor of Commerce degree from the University of Saskatchewan and is a Certified General Accountant.

**Garry W. Bieber**

Mr. Bieber is Vice-President, Special Projects of the Corporation and was appointed to that position effective January 1, 2014. Prior to his appointment as Vice-President, Special Projects, Mr. Bieber was Vice-President, Production of the Corporation and was appointed as Vice-President, Production of Freehold Resources and Rife on August 13, 2008. Mr. Bieber joined Rife in 1985 as Chief Engineer and from 1991 through 2008 he was Manager of Production. Mr. Bieber has a Bachelor of Science degree in Geological Engineering from the University of Saskatchewan and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Mr. Bieber intends to retire on April 1, 2014.

**Scott W. Hadley**

Mr. Hadley is Vice-President, Exploration of the Corporation and Rife and has held such positions since joining Rife on June 3, 2013. Mr. Hadley is a Professional Geologist with 25 years of experience working primarily in the Western Canada and Michigan Basins. Prior to joining Rife, Mr. Hadley was Vice-President, Exploration of Santonia Energy Inc. (previously Fairborne Energy Ltd.), where he has held positions of increasing responsibility since 2002. He has a Bachelor of Science (Honors) degree in Geology from the University of Western Ontario and a Master of Science degree in Geology from McMaster University. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA), as well as a member of the Canadian Society of Petroleum Geologists (CSPG), the American Association of Petroleum Geologists (AAPG), and the Canadian Well Logging Society (CWLS).

**Daniel R. Moore**

Mr. Moore is Vice-President, Production of the Corporation and Rife and has held such positions since January 1, 2014. Mr. Moore joined Rife in 2011 as Manager, Engineering and was promoted to Chief Engineer in 2012. Prior to joining Rife he was Vice-President, Engineering of Stetson Oil and Gas Ltd. He has a Bachelor of Science degree in Mechanical Engineering from the University of Alberta and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

**Michael J. Stone**

Mr. Stone is Vice-President, Land of the Corporation and was appointed as Vice President, Land of Freehold Resources and Rife on March 1, 2010. Mr. Stone began his association with Rife in January 2009 as a Manager, Land Negotiations and Business Development. Prior to joining Rife, Mr. Stone was Vice-President, Land with Real Resources Ltd. Mr. Stone has a Bachelor of Commerce degree from the University of Calgary and is a member of the Canadian Association of Petroleum Landmen (CAPL).

**Michael J. Mogan**

Mr. Mogan, Controller of the Corporation, was appointed Controller of Freehold Resources effective August 13, 2008. Mr. Mogan joined Rife in 2003 as Senior Accountant and was the Manager, Financial Accounting prior to his current role. He is a Certified Management Accountant (CMA).

**Karen C. Taylor**

Ms. Taylor, Corporate Secretary of the Corporation, joined Rife in February 1997 as Manager, Corporate Communications and held the position of Manager, Investor Relations from January 1999 to August 2013. Her appointment as Corporate Secretary of Freehold Resources and Rife was effective February 27, 2008. Ms. Taylor is a member of the Canadian Society of Corporate Secretaries (CSCS).

**Corporate Cease Trade Orders or Bankruptcies**

During the past ten years, none of the current directors and executive officers of Freehold is or has been a director, chief executive officer or chief financial officer of any company that: (i) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, while that person was acting in the capacity as director, chief executive officer or chief financial officer; (ii) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, 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. None of the directors or executive officers of Freehold is as at the date of the annual information form, or has been within 10 years before the date of the information circular, a director or executive officer of any 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.

**Personal Bankruptcies**

None of the directors or executive officers of Freehold has nor any Shareholder holding sufficient number of securities of the Corporation to affect materially the control of the Corporation, within the past 10 years, 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 proposed director.

**Penalties or Sanctions**

No director, executive officer or promoter of Freehold nor any Shareholder holding sufficient number of securities of the Corporation to affect materially the control of the Corporation, has been subject to any penalties or sanctions imposed by a court, securities regulatory authority or other regular authority or has entered into a settlement agreement with a securities regulatory authority.

**Audit Committee**

The full text of the audit committee mandate is included in Appendix C of this AIF.

**Composition of Audit Committee**

Freehold's audit committee consists of Mr. Rodger Tourigny (Chair), Mr. Arthur Korpach and Mr. Aidan Walsh. All members of the audit committee are independent and financially literate as those terms are used under National Instrument 52-110 *Audit Committees*. See "*Governance – Board of Directors of Freehold*".

### **Pre-Approval Policies and Procedures**

The audit committee pre-approves all non-audit services to be provided to the Corporation by the external auditors. Prior to the commencement of the Corporation's fiscal year, the audit committee pre-approves expenditures with a dollar limit for services related to consultations as to the accounting or disclosure treatment of transactions, and for expenditures with a dollar limit for services related to taxation matters. The audit committee must pre-approve any costs that exceed these limits.

### **EXTERNAL AUDITOR SERVICE FEES**

	Year Ended December 31	
	2013	2012
Audit fees <sup>(1)</sup>	168,000	281,000
Audit-related fees <sup>(2)</sup>	-	35,000
Tax fees <sup>(3)</sup>	15,000	22,330
All other fees	-	-
<b>Total</b>	<b>183,000</b>	<b>338,330</b>

- (1) Audit fees consist of fees for the audit of Freehold's annual financial statements, reviews of interim consolidated financial statements for the first, second, and third quarters of the respective year, or services that are normally provided in connection with statutory and regulatory filings or engagements.
- (2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of Freehold's financial statements and are not reported as Audit Fees.
- (3) Tax fees consist of fees for tax compliance and advisory services.

## **THE MANAGER**

### **Business of the Manager**

The Manager provides comprehensive oil and gas company management and operational services to Freehold, Freehold Resources, and the Partnership. The Manager is a wholly-owned subsidiary of Rife. Pursuant to an agreement between Rife and the Manager dated November 25, 1996, Rife provides the Manager, on a contract basis, with all necessary personnel, equipment and facilities required to provide management and operational services to Freehold, Freehold Resources and the Partnership.

### **Employees**

Freehold has no employees but rather is managed by the Manager pursuant to the Management Agreement. On December 31, 2013, Rife had 90 full and part-time employees in the Calgary office and 15 full-time employees in their field operations, the majority of whom are on contract to the Manager. These personnel also render services to Rife and Canpar.

### **Management Agreement**

Pursuant to the Management Agreement, Freehold, Freehold Resources and the Partnership engaged the Manager to:

- a. administer all matters relating to the securities of Freehold, including the Common Shares, and the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold, Freehold Resources and the Partnership, including: (i) determining the total amount owing to Freehold and its subsidiaries and partnerships from third parties and conducting joint venture audits as required; (ii) determining the total amounts owing to Shareholders and arranging for dividends to Shareholders, subject to the supervision of Freehold; (iii) providing Shareholders with periodic reports on the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold and its subsidiaries and partnerships; and (iv) providing Shareholders with financial reports and tax information relating to the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold and its subsidiaries and partnerships;
- b. provide management services for the economic and efficient exploitation of oil and natural gas properties;

- c. operate oil and natural gas properties that Freehold and its subsidiaries and partnerships are entitled to operate and monitor the activities of third party operators;
- d. recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for Freehold and its subsidiaries and partnerships;
- e. negotiate on behalf of Freehold and its subsidiaries and partnerships all exploitation and development agreements, operating agreements, working agreements, farmin and farmout agreements, leases and other documents relating to the exploitation of the oil and natural gas properties as may be advisable;
- f. recommend and negotiate banking arrangements for Freehold; and
- g. provide office space, office furnishings and equipment and personnel necessary for the proper administration of the assets of Freehold and its subsidiaries and partnerships.

In exercising its power and discharging its duties under the Management Agreement, the Manager will be required to exercise that degree of care, diligence and skill that a reasonably prudent advisor and manager in respect of oil and gas properties in western Canada would exercise in comparable circumstances.

The Management Agreement is renewed every three years for a three year term unless the termination of the Management Agreement at the end of a term has been approved by a special resolution of holders of Common Shares and the Manager is given 12 months written notice of termination or unless Freehold is given 12 months written notice of termination by the Manager prior to the end of a term. The current term of the Management Agreement will expire November 2016.

The Management Agreement may be terminated by Freehold at any time without the payment of compensation to the Manager if the Manager institutes bankruptcy proceedings, seeks relief under bankruptcy law, consents to the appointment of a receiver, voluntarily suspends transaction of its usual business, is declared bankrupt or insolvent, if a receiver is appointed in respect of the Manager, or if the Manager fails to carry out its material obligations under the Management Agreement and does not commence to cure such failure within 30 days of written notice being given.

There may be circumstances in which the interests of the Manager will conflict with those of the Shareholders. The Manager provides similar management services to Canpar and Rife and may provide similar management services to others in the future. The Manager may acquire oil and gas properties on its own behalf or on behalf of persons other than Freehold. The Manager may manage and administer such additional properties, as well as enter into other types of energy-related management and advisory activities.

In resolving such conflicts, decisions will be made by the Manager on a basis consistent with the objectives and financial resources of each group of interested parties, the time limitations on investment of such financial resources, and on the basis of operating efficiencies having regard to the then current holdings of properties of each group of interested parties all consistent with the duties of the Manager to each such group of persons. The Manager will use all reasonable efforts to resolve such conflicts of interest in a manner which will treat Freehold and the other interested party fairly, taking into account all of the circumstances of Freehold and such interested party and will act honestly and in good faith in resolving such matters.

Proceeds relating to subscription offerings, royalty income and other revenues generated from or associated with any interest of Freehold may not be commingled with the funds of any other entity that is managed by the Manager.

The Manager will be paid the Management Fee for providing all of the management services. The Manager will be indemnified by Freehold in respect of certain damages that it may suffer in discharging its obligations under the Management Agreement provided that such damages do not arise from the fraud, wilful default, gross negligence or bad faith of the Manager.

The Board of Directors will review on an ongoing basis both the nature and extent of the services required of the Manager and the costs of providing the same. All amendments to the Management Agreement must be approved by a majority of the members of the Board of Directors.

## **Compensation**

The Manager will be compensated as follows for providing services to the Corporation, Freehold Resources and the Partnership.

### ***Management Fee***

The Manager receives a Management Fee, paid in Common Shares, based on the number of issued and outstanding Common Shares at the end of each quarter. The Management Fee is adjusted, based on the total issued and outstanding Common Shares, so that the quarterly Management Fee is always in the same proportion relative to the outstanding Common Shares, excluding Common Shares issued as payment of the Management Fee. The quarterly Management Fee is calculated by multiplying 20,000 (which is the initial number of trust units of Freehold Royalty Trust paid to the Manager as the Management Fee pursuant to the Management Agreement) by the fraction the numerator of which is the number of Common Shares issued and outstanding at the end of the quarter (excluding all Common Shares (or trust units of Freehold Royalty Trust) issued to the Manager as part of the Management Fee) and the denominator of which is 26,400,000 (which was the initial number of trust units of Freehold Royalty Trust outstanding when the Management Agreement was originally entered into). As at December 31, 2013, the quarterly Management Fee was 48,845 Common Shares.

In conjunction with the implementation of the plan of arrangement that resulted in Freehold, directly or indirectly, acquiring all of the assets and assuming all of the liabilities of Freehold Royalty Trust, holders of trust units of Freehold Royalty Trust approved the reservation up to 1,000,000 Common Shares which may be issued as payment of the Management Fee under the Management Agreement. Presently under the Management Agreement, there are 442,373 Common Shares available for issuance as payment of the Management Fee.

### ***General and Administrative Costs***

The Manager is reimbursed for general and administrative costs incurred on behalf of the Corporation, Freehold Resources and the Partnership (in 2013 – 34.5%). General and administrative costs are generally charged to the Corporation, Freehold Resources and the Partnership by the Manager based on time spent and direct costs incurred in fulfilling the obligations of the Manager to the Corporation, Freehold Resources and the Partnership pursuant to the Management Agreement.

### ***Long-Term Incentive Plan***

The Corporation also accrues for its proportionate share (in 2013 – 34.5%) of a long-term incentive plan for employees of the Manager. The liability is estimated at the end of each quarter based on the quarter-end Common Share price and performance factors. The related compensation charges are recognized over the three-year vesting period.

### ***Manager's Annual Bonus Plan***

The Corporation pays its proportionate share (in 2013 – 34.5%) of an annual cash bonus plan for employees of the Manager.

### ***Directors' Deferred Share Unit Plan***

The Deferred Share Unit Plan consists of fully vested Deferred Share Units, granted annually to non-management directors of the Corporation. Dividends to Shareholders declared by the Corporation prior to redemption are assumed to be reinvested in notional share units on the date of dividend.

### ***Retirement Benefit***

The Corporation participates in its proportionate share (in 2013 – 34.5%) of a retirement benefit for certain employees of the Manager. The retirement benefit is payable in four equal instalments upon retirement. Service costs are amortized on a straight-line basis over the expected average remaining service lifetime.

## Directors and Officers of the Manager

The name, province of residence, position held and principal occupation of each director and officer of the Manager are set out below:

<b>Name and Province of Residence</b>	<b>Position with the Manager</b>	<b>Principal Occupation</b>	<b>Director or Officer of the Manager Since</b>
Thomas J. Mullane Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer, Rife	July 18, 2012
Darren G. Gunderson Alberta, Canada	Vice-President, Finance and Chief Financial Officer and Director	Vice-President, Finance and Chief Financial Officer, Rife	July 2, 2007
Garry W. Bieber Alberta, Canada	Vice-President, Special Projects	Vice-President, Special Projects, Rife	August 13, 2008
Scott W. Hadley Alberta, Canada	Vice-President, Exploration	Vice-President, Exploration, Rife	June 3, 2013
Daniel R. Moore Alberta, Canada	Vice-President, Production	Vice-President, Production Rife	January 1, 2014
Michael J. Stone Alberta, Canada	Vice-President, Land	Vice-President, Land, Rife	March 1, 2010
Alan G. Glessing Alberta, Canada	Controller	Controller, Rife	September 18, 2008
Karen C. Taylor Alberta, Canada	Corporate Secretary	Corporate Secretary, Rife	February 1, 2008

As at March 6, 2014, the directors and senior officers of the Manager as a group beneficially owned, directly or indirectly, or exercised control or direction over 4,500 Common Shares. Rife owns 100% of the outstanding shares in the capital of the Manager. All of the shares of Rife are owned by the CN Pension Trust Funds.

## CONFLICTS OF INTEREST

There may be situations in which the interests of the Manager will conflict with those of the Shareholders. As part of the ordinary course of business of the Manager, the Manager may continue to acquire oil and natural gas properties on its own behalf and on behalf of persons other than Freehold. The Manager may manage and administer such properties, as well as enter into other types of energy-related management, advisory and investment activities. Thus, neither the Manager nor its management will carry on their full-time activities on behalf of Freehold and, when acting on its own behalf or on behalf of others, may at times act in contradiction to or in competition with the interests of the Shareholders.

In resolving such conflicts, decisions will be made by the Manager on a basis consistent with the objectives and financial resources of each group of interested parties, the time limitations on investment of such financial resources, and on the basis of operating efficiencies having regard to the then current holdings of properties of each group of interested parties all consistent with the duties of the Manager to each such group of persons. The Management Agreement contains provisions that require the Manager to make disclosure to the Board of Directors of the fact and substance of any particular conflict of interest and to use all reasonable efforts to resolve such conflicts of interest in a manner that will treat Freehold and the other interested party fairly taking into account all of the circumstances of Freehold and such interested party and to act honestly and in good faith in resolving such matters.

Although the Manager provides advisory and management services to Freehold, the Board of Directors supervises the management of the business and affairs of Freehold. The Board of Directors makes significant operational decisions and all decisions relating to: (i) the issuance of additional Common Shares; (ii) the acquisition and disposition of properties for a purchase price or proceeds in excess of \$10 million; (iii) the approval of capital expenditure budgets; (iv) the establishment of credit facilities; and (v) the determination of the amount of dividends to Shareholders.

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

## **LEGAL PROCEEDINGS AND REGULATORY ACTIONS**

Other than as set out below, to the knowledge of management of Freehold as at the date hereof, there are no legal proceedings that Freehold is a party to, or that any of Freehold's property is the subject of, that is material to Freehold, and there are no such material legal proceedings known to be contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" to Freehold if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of Freehold's consolidated current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, we have included the amount involved in the other proceedings in computing the percentage.

Freehold is currently subject to a claim against it filed in the second quarter of 2009 in the Alberta Court of Queen's Bench for \$9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, the Corporation has assessed the claim, believes it has no merit, and intends to defend itself aggressively in the claim. The claim's outcome is not determinable; therefore, no liability has been recorded in the Corporation's financial statements.

There were no: (i) penalties or sanctions imposed against Freehold by a court relating to securities legislation or by a security regulatory authority during its most recently completed financial year or during the current financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against Freehold that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements Freehold entered into before a court relating to securities legislation or with a securities regulatory authority during Freehold's most recently completed financial year or during the current financial year.

## **INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

Other than as disclosed below or herein, there were no material interests, direct or indirect, of any directors or executive officers of the Manager, directors or executive officers of Freehold, any Shareholder who beneficially owns more than 10% of the Common Shares or any known associate or affiliate of such persons in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Corporation.

The Manager is a wholly-owned subsidiary of the CN Pension Trust Funds, which held 18,412,957 Common Shares as at March 6, 2014, representing approximately 27% of the outstanding Common Shares. The Manager receives certain compensation for providing management services to the Corporation, Freehold Resources and the Partnership as described under "*The Manager*". All transactions during 2013 were in the normal course of operations and were measured at the exchange amount, which is the amount of consideration established and agreed to by Freehold and the Manager.

## **TRANSFER AGENT AND REGISTRAR**

Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Common Shares.

## MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year but which are still in effect, are the following:

- (i) the Governance Agreement dated December 31, 2010, as described under the heading “*Governance – Governance Agreement*”;
- (ii) the Management Agreement dated January 1, 2011, as described under the heading “*The Manager – Management Agreement*”; and
- (iii) the credit facility between the Corporation (as successor to the Freehold Royalty Trust) and its lenders dated May 10, 2005, and amended on May 24, 2006, March 26, 2007, August 31, 2007, May 29, 2008, May 22, 2009, May 20, 2010, May 20, 2011, December 22, 2011, May 11, 2012, and May 15, 2013 as described under “*Borrowing*”.

## INTEREST 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 under NI 51-102 by the Corporation during, or relating to, the Corporation’s most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are KPMG LLP, our independent auditors, Trimble, our independent engineering evaluators, and Seaton-Jordan, our independent land evaluators.

### Interest of Experts

KPMG LLP is the auditor of the Corporation and is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants, Alberta. As at the date hereof, the designated professionals (as defined in NI 51-102) of Trimble, as a group, beneficially owned, directly or indirectly, less than 1% of our outstanding securities including the securities of our associate or affiliate entities. The designated professionals of Seaton-Jordan, as a group, beneficially owned, directly or indirectly, less than 1% of our outstanding securities including the securities of our associate or affiliate entities.

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

## ADDITIONAL FINANCIAL AND OTHER INFORMATION

Additional information about the Corporation may be found on SEDAR at [www.sedar.com](http://www.sedar.com). Information about remuneration and indebtedness of directors and officers of Freehold and the Manager, principal holders of the Common Shares and securities authorized for issuance under security-based compensation of the Corporation, will be contained in the Information Circular – Management Proxy Statement of the Corporation to be dated on or about April 2, 2014, which relates to the Annual Meeting of Shareholders to be held on May 14, 2014. Additional financial information is provided in Freehold’s consolidated financial statements for the year ended December 31, 2013 and the accompanying management’s discussion and analysis.

For copies of our consolidated financial statements of the Corporation and accompanying management’s discussion and analysis and the Information Circular – Proxy Statement and additional copies of the AIF (in certain circumstances reasonable fees may apply) please contact:

Corporate Secretary  
Freehold Royalties Ltd.  
Suite 400, 144 – 4<sup>th</sup> Avenue S.W.  
Calgary, Alberta T2P 3N4  
Telephone: 403-221-0802  
Fax: 403-221-0888

## APPENDIX A

### Form 51-101F2

### Report on Reserves Data by Independent Qualified Reserves Evaluators

To the Board of Directors of Freehold Royalties Ltd. (the “**Corporation**”) and Rife Resources Management Ltd., as manager of the Corporation:

1. We have evaluated the Corporation’s reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Corporation’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%, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation’s management:

Independent Qualified Reserves Evaluator	Description and Preparation of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (\$000s)			
			Audited	Evaluated	Reviewed	Total
Trimble Engineering Associates Ltd.	Reserve and Present Worth Appraisal of Certain Oil and Gas Properties At December 31, 2013 Dated January 22, 2014	Canada	0	\$646,037	0	\$646,037

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

Executed as to our report referred to above:

Trimble Engineering Associates Ltd., Calgary, Alberta, Canada, March 6, 2014.

Per: (signed) “Stephen C. Trimble”  
 Stephen C. Trimble, P.Eng.  
 President & Managing Director

## APPENDIX B

### Form 51-101F3

### Report of Management and Directors on Oil and Gas Disclosure

Management of Freehold Royalties Ltd. (the “**Corporation**”) is responsible for the preparation and disclosure of information with respect to the Corporation’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, 2013 estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation’s reserves data. The report of the independent qualified reserves evaluator is presented in Appendix A of this Annual Information Form.

The Reserves Committee of the Board of Directors of the Corporation has

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

The Reserves Committee of the Board of Directors of the Corporation has reviewed the 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, on the recommendation of the Reserves Committee, approved

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

(signed) “Thomas J. Mullane”  
Thomas J. Mullane  
President, Chief Executive Officer and Director

(signed) “Daniel R. Moore”  
Daniel R. Moore  
Vice-President, Production

(signed) “David J. Sandmeyer”  
David J. Sandmeyer  
Director and Chair, Reserves Committee

(signed) “Peter T. Harrison”  
Peter T. Harrison  
Director and Member, Reserves Committee

DATED as of this 6<sup>th</sup> day of March, 2014.

## APPENDIX C

### Audit Committee Mandate

#### Role and Objective

The Audit Committee (the “**Committee**”) is a committee of the board of directors (the “**Board**”) of Freehold Royalties Ltd. (“**Freehold**”) to which the Board has delegated certain responsibilities for oversight of the nature and scope of the annual audit, management’s reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee are as follows:

1. to assist directors in meeting their responsibilities especially for accountability, in respect of the preparation and disclosure of the financial statements of Freehold and related matters;
2. to provide better communication between directors and the external auditors;
3. to enhance the external auditors’ independence;
4. to increase the transparency, credibility and objectivity of financial reporting; and
5. to strengthen the role of the independent directors by facilitating in-depth discussions between directors on the Committee, management and the external auditors.

#### Membership of Committee

1. The Committee will be comprised of at least three directors, all of whom are independent (as such term is used in National Instrument 52-110 – Audit Committees (NI 52-110)).
2. The Board will have the power to appoint the Committee Chair.
3. All of the members of the Committee will be financially literate. The Board has adopted the definition for financial literacy used in NI 52-110.

#### Meetings

1. At all meetings of the Committee, every question will be decided by a majority of the votes cast. In case of an equality of votes, the Committee Chair is not entitled to a second or deciding vote.
2. 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.
3. 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 (“**CFO**”) will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Committee Chair.
4. The Committee will forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board.
5. The Committee will meet in-camera with the external auditors at least quarterly (in connection with the preparation of the annual and quarterly financial statements) and at such other times as the external auditors and the Committee consider appropriate.
6. The Committee will meet in-camera, without members of management or management directors, at the end of each meeting unless all the members have all indicated there is no need for an in-camera session. The Committee may invite other directors, members of management, and advisors to attend all or part of any in-camera session, as it deems advisable.

#### Mandate and Responsibilities

The mandate and responsibilities of the Committee will be as set forth below:

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

2. satisfy itself on behalf of the Board with respect to Freehold's internal control systems, which include:
  - (a) identifying, monitoring and mitigating business risks; and
  - (b) ensuring compliance with legal, ethical and regulatory requirements;
3. review the annual and quarterly financial statements of Freehold prior to their submission to the Board for approval. The process should include but not be limited to:
  - (a) reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
  - (b) reviewing significant accruals, reserves or other estimates such as impairment testing;
  - (c) reviewing accounting treatment of unusual or non-recurring transactions;
  - (d) ascertaining compliance with covenants under loan agreements;
  - (e) reviewing adequacy of reclamation provisions;
  - (f) reviewing disclosure requirements for commitments and contingencies;
  - (g) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
  - (h) reviewing unresolved differences between management and the external auditors; and
  - (i) obtaining explanations of significant variances with comparative reporting periods;
4. review the financial statements, prospectuses, management discussion and analysis, annual information forms, earnings news releases, and all public disclosure containing audited or unaudited financial information before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Freehold's disclosure of all other financial information and will periodically assess the accuracy of those procedures;
5. recommend to the Board the annual appointment of external auditors, and in so doing:
  - (a) annually review the performance and independence of the external auditors;
  - (b) review the terms of engagement of the auditor, including the compensation of the auditors;
  - (c) confirm that the auditors will report directly to the Committee;
  - (d) 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
  - (e) review and approve any non-audit services to be provided by the auditors' firm and consider the impact on the independence of the auditors;
6. review with external auditors, and the internal auditor if one is appointed by Freehold, their assessment of the internal controls of Freehold, 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 audit plan and, upon completion of the audit, their reports upon the financial statements of Freehold and its subsidiaries;
7. pre-approve all non-audit services to be provided to Freehold or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time;
8. review, on an annual basis, the risk management policies and procedures of Freehold, including hedging, litigation and insurance;
9. review and approve management's hiring policies regarding current and former partners and employees of the present and former external auditor;
10. establish procedures for:
  - (a) the receipt, retention and treatment of complaints received by Freehold regarding accounting, internal accounting controls or auditing matters; and
  - (b) the confidential, anonymous submission by employees of Rife Resources Management Ltd. (the "**Manager**") of concerns regarding questionable accounting or auditing matters;
11. the Committee will have the authority to investigate any financial activity of Freehold. All employees of the Manager are to cooperate as requested by the Committee; and
12. the Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling their responsibilities at the expense of Freehold without any further approval of the Board.