CARDINAL
ENERGY LTD.

2013 Annual Information Form

March 28, 2014

TABLE OF CONTENTS

GLOSSARY

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Board or **Board of Directors** means our board of directors.

Cardinal, we, us or **our** means Cardinal Energy Ltd.

Assets

Bantry Assets means the petroleum and natural gas assets acquired by Cardinal in the Bantry area of Alberta on September 26, 2013.

Chauvin 1 Assets means the petroleum and natural gas assets acquired by Cardinal in the Chauvin area of Alberta on October 17, 2012.

Chauvin 2 Assets means the petroleum and natural gas assets acquired by Cardinal in the Chauvin area of Alberta on December 14, 2012.

Loverna Assets means the petroleum and natural gas assets acquired by Cardinal in the Hudson/Loverna area of Alberta and Saskatchewan on July 5, 2012.

SE Alberta Assets means the petroleum and natural gas assets acquired by Cardinal in Southeast Alberta on December 17, 2013.

Wainwright Assets means the petroleum and natural gas assets acquired by Cardinal in the Wainwright area of Alberta on January 23, 2013.

Reserves

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.

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

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

Sproule means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta.

Sproule Report means the report prepared by Sproule dated March 21, 2014, evaluating our crude oil, natural gas and natural gas liquids reserves attributable to all of our assets as at December 31, 2013.

Securities and Other terms

Common Shares means our common shares as presently constituted.

Credit Facility means our $125 million syndicated credit facility, as more particularly described under the heading "*Description of our Capital Structure – Credit Facility*"

Pre-Consolidated Shares means our common shares as constituted immediately prior to being consolidated on a basis of 3 to 1 on September 9, 2013.

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

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Bbls/d	barrels per day
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	thousand stock tank barrels of oil
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
GJ	gigajoule

Other

AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
$Cdn	Canadian dollars
m^3	cubic metres
MBoe	thousand barrels of oil equivalent.
MMBoe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s	thousands of dollars
$MM	millions of dollars

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.289
Feet	metres	0.305
Metres	feet	3.281
Miles	kilometres	1.609
Kilometres	miles	0.621
Acres	hectares	0.405
Hectares	acres	2.471
Gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

CONVENTIONS

Certain terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form, including documents incorporated by reference herein, contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to our future events or our future performance. All information and statements other than statements of historical fact contained in this Annual Information Form are forward-looking statements. Such forward-looking statements may be identified by looking for words such as "about", "approximately", "may", "believe", "expects", "will", "intends", "should", "could", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "continues" or similar words or the negative thereof or other comparable terminology. In addition, there are forward looking statements in this Annual Information Form under the headings: "*General Description of Our Business*" as to our business plan and strategy; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data*" as to our reserves and future net revenue from our reserves, income taxes and pricing, exchange and inflation rates; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data*" as to the development of our proved undeveloped reserves and probable undeveloped reserves, future developments costs, our plans to fund future developments costs through a combination of internally generated cash flow, debt and equity issuances and anticipated funding costs; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information*" as to our exploration and development plans and opportunities, anticipated land expiries, hedging and marketing policies, abandonment and reclamation obligations, tax horizon and future production; and "*Dividend Policy*" as to our dividend policy and the future payment of dividends.

In addition to the forward-looking statements identified above, this Annual Information Form contains forward-looking statements pertaining to the following:

- waterflood implementation opportunities and the results therefrom;
- recovery factors;
- well completions and the timing thereof;
- the performance characteristics of our oil and natural gas properties;
- expectation of future production rates, volumes and product mixes;
- projections of market prices and costs, and exchange and inflation rates;
- supply and demand for oil and natural gas;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions, development and optimization;
- treatment under governmental regulatory regimes and tax laws;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production and timing of results therefrom;
- fluctuations in depletion, depreciation and accretion rates;
- expected changes in regulatory regimes in respect of royalty curves and regulatory improvements and the effects of such changes;
- plans to expand recovery from certain of our properties; and
- our business plans and strategy.

Statements relating to "reserves" are also deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- volatility in market prices for oil and natural gas and foreign exchange rates;
- operational risks and 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;
- geological, technical, drilling and processing problems;
- fluctuation in foreign exchange or interest rates;
- stock market volatility;
- environmental risks;
- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing of our exploration and development program;
- fluctuations in the costs of borrowing;
- political or economic developments;
- ability to obtain regulatory and other third party approvals;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against us;
- 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*".

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding, among other things: the timing of obtaining regulatory approvals; commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; access to capital; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; and future operating costs.

We have included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements in accordance with generally accepted accounting principles in Canada requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. **The information contained in this Annual Information Form, including the documents incorporated by reference herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form are made as of the date of this Annual Information Form and we undertake no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

BARREL OF OIL EQUIVALENCY

The term "Boe" may be misleading, particularly if used in isolation. A Boe conversion ratio of six thousand cubic feet of natural gas to barrels of oil (6 Mcf: 1 Bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. **Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value.**

NOTE ON SHARE REFERENCES

On September 9, 2013 we effected a consolidation of our common shares as then constituted on the basis of 3 Pre-Consolidated Shares for every one common share. All references to Common Shares in this Annual Information Form are to our Common Shares as presently constituted on a post-consolidated basis and all references herein to Pre-Consolidated Shares are to our common shares prior to the September 9, 2013 consolidation. We have chosen to express all values relating to our share capital in this Annual Information Form on a post-consolidated basis. For share capital issued prior to September 9, 2013, readers should multiply any referenced number of Common Shares by a factor of 3 to arrive at the approximate equivalent number of Pre-Consolidated Shares. In addition, readers should divide the issuance price of any Common Share or the exercise price of any securities to acquire Common Shares by 3 to arrive at the approximate equivalent issuance price or exercise price for Pre-Consolidated Shares or securities to acquire Common Shares.

GAAP AND NON-GAAP MEASURES

Throughout this Annual Information Form we use the terms "cash flow from operations", "cash flow from operations per share", "netback", "net debt", "free cash flow", "simple payout ratio" and "total payout ratio". These terms do not have a standardized prescribed meaning under generally accepted accounting principles in Canada and these measurements may not be comparable with the calculation of similar measurements by other entities.

"Cash flow from operations" is calculated based on cash flow from operating activities before the change in non-cash working capital and decommissioning expenditures. We believe the timing of collection, payment or incurrence of these items involves a high degree of discretion and as such may not be useful for evaluating our operating performance. Cash flow from operations per share is calculated using the same weighted average number of Common Shares outstanding used in calculating earnings per share. We use cash flow from operations as a key measure to assess our ability to finance dividends, operating activities and capital expenditures. Cash flow from operations should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with generally accepted accounting principles in Canada as an indication of our performance.

A reconciliation of cash flow from operating activities to cash flow from operations is as follows:

($000s)	Year ended	
	December 31, 2013	December 31, 2012
Cash flow from operating activities	8,913	686
Decommissioning expenditures	262	-
Change in non-cash working capital	639	128
Cash flow from operations	9,814	814

"Net debt" is calculated as total bank debt (long term bank debt plus the current portion of bank debt) plus other current liabilities less current assets adjusted for the fair value of financial investments. We use net debt to analyze our financial position and leverage.

"Free cash flow" represents cash flow from operations less cash dividends declared and less our expectation of the amount of capital expenditures necessary to maintain our base production. "Total payout ratio" represents the ratio of the sum of cash dividends declared plus our expectation of the amount of capital expenditures necessary to maintain our base production divided by cash flow from operations. "Simple payout ratio" represents the ratio of the amount of cash dividends declared, divided by cash flow from operations. Free cash flow and total payout ratio are other key measures to assess our ability to finance dividends, operating activities and capital expenditures.

"Netback" is calculated on a per Boe basis and is determined by deducting royalties and operating expenses from petroleum and natural gas revenue. We use netback to better analyze the operating performance of our petroleum and natural gas assets against prior periods.

CARDINAL ENERGY LTD.

General

We were incorporated under the *Business Corporations Act* (Alberta) as 1577088 Alberta Ltd. on December 21, 2010. On May 25, 2012, we changed our name to "Cardinal Energy Ltd.". On June 28, 2012 we amended our Articles to change the rights, privileges, restrictions and conditions in respect of our Common Shares, including changes to set forth the terms and conditions pursuant to which we may issue stock dividends declared on the Common Shares. On July 27, 2012 we amended our Articles to remove the private company restrictions. See "*Description of our Capital Structure*".

On September 9, 2013, we filed Articles of Amendment to consolidate our Pre-Consolidated Shares on a basis of 3 Pre-Consolidated Shares for each one Common Share and to change the rights, privileges, restrictions and conditions in respect of our Common Shares, specifically to amend the percentage of the average market price used when calculating a stock dividend on our Common Shares. See "*Note on Share References*" and "*Description of our Capital Structure*".

Our head office is located at Suite 1400, 440 – 2nd Avenue SW, Calgary, Alberta T2P 5E9 and our registered office is located at Suite 2400, 525 – 8th Avenue SW, Calgary, Alberta T2P 1G1. We do not have any subsidiaries.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

We commenced operations in May of 2012 and through a series of acquisitions, we successfully established two core operating areas in Chauvin and Wainwright. In the third quarter of 2013, we completed the acquisition of the Bantry Assets, a new focus area in which we identified development drilling opportunities. On December 17, 2013, we completed the acquisition of the SE Alberta Assets, our initial public offering and our Common Shares commenced trading on the Toronto Stock Exchange.

Acquisitions and Equity Financings 2012

In July of 2012, we completed a non-brokered private placement of 666,667 Common Shares issued as "flow-through shares" pursuant to the *Income Tax Act* (Canada) at a price of $3.00 per share for total gross proceeds of $2 million and a non-brokered private placement of 2,833,333 units at a price of $3.00 per unit for gross proceeds of $8.5 million. Each unit consisted of one Common Share and one-half of one share purchase warrant. Each whole warrant entitled the holder to acquire one Common Share for the exercise price of $3.00. The warrants vest in equal parts over five years and are only exercisable if the market value of our Common Shares is greater than $6.00 per Common Share, with the first vesting date on December 31, 2012 and on or after December 31 of each year thereafter and expire on July 30, 2017. In addition, on July 5, 2012, we closed the acquisition of the Loverna Assets. Total consideration for the Loverna Assets was $1.45 million in cash before closing adjustments. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

In August of 2012, we completed a non-brokered private placement of 410,417 Common Shares at a price of $4.80 per share for total gross proceeds of $1.97 million.

In September of 2012, we secured a $60 million revolving demand credit facility from a Canadian financial institution and closed a non-brokered private placement of 422,915 Common Shares at a price of $4.80 per share for total gross proceeds of $2.03 million.

On October 17, 2012, we closed the acquisition of the Chauvin 1 Assets. Total consideration for the Chauvin 1 Assets was $51 million in cash before closing adjustments. The purchase price was funded in part through the net proceeds of a private placement of 4,333,333 Common Shares at a price of $6.75 per share for gross proceeds of $29.25 million.

On December 14, 2012, we closed the acquisition of the Chauvin 2 Assets. Total consideration for the Chauvin 2 Assets was $22 million in cash before closing adjustments. The purchase price was funded in part through the net proceeds of a private placement of 2,425,000 Common Shares at a price of $8.25 per share for gross proceeds of approximately $20 million.

For more information about our Chauvin assets, see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

Acquisitions and Financings 2013

On January 23, 2013, we acquired the Wainwright Assets for an aggregate purchase price of $4.6 million, before closing adjustments, which was satisfied through the issuance of 66,667 Common Shares at a deemed price of $8.25 per share and a payment of $4.05 million in cash, see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

On March 31, 2013, we closed a non-brokered private placement of 113,333 Common Shares at a price of $9.00 per share which were issued on "flow-through basis" pursuant to the *Income Tax Act* (Canada) for aggregate gross proceeds of $1.02 million.

On May 29, 2013, we acquired undeveloped land acreage in the Hudson and Esther areas of Alberta for the aggregate purchase price of $254,375 which was satisfied through the issuance of 30,833 Common Shares at a price of $8.25 per share.

On September 26, 2013, we completed the acquisition of the Bantry Assets for the aggregate purchase price of $21.75 million prior to closing adjustments.

On December 17, 2013, we closed the acquisition of the SE Alberta Assets. Total consideration for the SE Alberta Assets was $210 million in cash, prior to customary closing adjustments. The purchase price was funded through the net proceeds of our initial public offering of 21,428,571 Common Shares at a price of $10.50 per Common Share which closed on December 17, 2013. In connection with our initial public offering, we became a reporting issuer in all the provinces of Canada (except Quebec) on December 10, 2013 and our Common Shares began trading on the Toronto Stock Exchange on December 17, 2013. Under the terms of the underwriting agreement we entered into with the underwriters with respect to the initial public offering, we granted the underwriters an over-allotment option, exercisable at their discretion, to purchase an additional 2,142,857 Common Shares. The underwriters exercised this option on December 23, 2013 resulting in additional gross proceeds of $22.5 million. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

Credit Facility

Contemporaneously with the closing of our initial public offering and the acquisition of the SE Alberta Assets, we entered into the Credit Facility which replaced the $60 million revolving facility we entered into in September of 2012. See "*Description of our Capital Structure*".

Recent Developments

On January 7, 2014 we announced that our Board of Directors approved a dividend policy of $0.05417 per common share per month for the first quarter of 2014. See "*Dividend Policy*".

On January 28, 2014 we closed two acquisitions of oil and gas assets in the Bantry area of Alberta for an aggregate purchase price of $27 million prior to customary adjustments, see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

On February 10, 2014 we closed a bought deal private placement of 2,187,500 Common Shares at a price of $12.80 per share for aggregate gross proceeds of $28 million.

Significant Acquisitions

The completion of the acquisition of the SE Alberta Assets on December 18, 2013 constituted a significant acquisition under Part 8 of National Instrument 51 102 – *Continuous Disclosure Obligations*. We filed a business acquisition report regarding the acquisition of the SE Alberta Assets dated February 7, 2014 and filed February 10, 2014, which is available on our SEDAR profile at www.sedar.com.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

We are an oil focused Canadian company built to provide investors with total returns comprised of yield plus growth. Our management is focused on a disciplined growth plan, both financially and operationally, while providing a dividend to our Shareholders, through the ownership of higher netback crude oil production currently focused in Southeast Alberta. See "*Statement of Oil and Gas Data – Other Oil and Natural Gas Information*".

We commenced operations in May of 2012 with the goal of building a dividend paying junior oil focused company from the ground up. Since we commenced operations, we have acquired several low decline crude oil properties. These acquisitions have provided us with a solid base of low decline oil and natural gas production, along with a large multi-year drilling inventory. The acquisitions included extensive operating infrastructure and they are located on all season access lands primarily in the Bantry (Alderson), Jenner, Chauvin and Wainwright areas of Alberta. See "*Statement of Oil and Gas Data – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

We have the objective of building core operating areas with sufficient scale of production as well as organic and acquisition growth prospects to achieve operational cost and production efficiency in each core area. We will manage exploration, production and marketing risks via the expertise of our experienced technical and management personnel.

Specialized Skill and Knowledge

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

Competitive Conditions

The oil and natural gas industry is intensely competitive and we are required to compete with a substantial number of other entities which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex. We believe that we have a strong competitive position in the areas in which we operate, see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*". Our business strategy is to develop core areas that have at least 1,000 Boe/d of production to enable us to have operating cost advantages and operating efficiencies in each core area.

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

Cycles

Our business is generally not cyclical. The exploration for and the development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including "freeze up" and "break up", affect access in certain circumstances. See "*Risk Factors – Seasonality*".

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on our earnings and our overall competitiveness. For a description of the financial and operational effects of environmental protection requirements on our capital expenditures, earnings and competitive position, see: "*Industry Conditions – Environmental Regulation*" and "*Risk Factors – Environmental*".

Employees

As at December 31, 2012, we had 22 full time employees located at our head office and 43 full-time employees located in the field.

Environmental, Health and Safety Policies

We promote safety and environmental awareness and protection through the implementation and communication of our environmental management and employee occupational health and safety programs, policies and procedures. Committee structures are established in our operations which are designed to allow for employee participation and development of policies and programs which provide employees with job orientation, training, instruction and supervision to assist them in conducting their activities in an environmentally responsible and safe manner.

We develop emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities in which we operate in order to effectively respond to an environmental incident should it arise. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks and operational exposures. We conduct audits of our operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist us in achieving the objectives of the described policies and programs.

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

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below is dated March 21, 2014. The statement is effective as of December 31, 2013. The Report of Management And Directors On Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data By Independent Qualified Reserves Evaluator in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by Sproule with an effective date of December 31, 2013 as contained in the Sproule Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged Sproule to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of our reserves are in Canada and, specifically, in the Provinces of Alberta and Saskatchewan.

We determined the future net revenue and present value of future net revenue after income taxes by utilizing Sproule's before income tax future net revenue and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different. Our financial statements for the year ended December 31, 2013 should be consulted for additional information regarding our taxes.

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the Sproule Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated. See "*Risk Factors*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								
Developed Producing	4,561	4,166	6,171	5,555	10,298	8,605	51	41
Developed Non-Producing	73	71	68	59	100	120	-	1
Undeveloped	731	560	208	197	831	660	13	10
TOTAL PROVED	5,365	4,797	6,447	5,811	11,229	9,386	65	53
PROBABLE	3,536	3,030	2,657	2,388	7,058	5,892	47	38
TOTAL PROVED PLUS PROBABLE	8,901	7,827	9,103	8,199	18,287	15,278	112	90

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)					
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% per Year $/Boe
PROVED:						
Developed Producing	344,616	306,713	264,931	232,027	206,682	23.66
Developed Non-Producing	5,171	4,325	3,691	3,204	2,821	24.57
Undeveloped	26,006	20,387	16,254	13,133	10,720	18.51
TOTAL PROVED	375,794	331,424	284,876	248,365	220,224	23.30
PROBABLE	256,547	159,137	110,403	82,063	63,891	17.15
TOTAL PROVED PLUS PROBABLE	632,341	490,561	395,278	330,428	284,115	21.18

	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	317,943	284,734	246,478	216,286	193,069
Developed Non-Producing	3,890	3,247	2,768	2,401	2,114
Undeveloped	19,544	14,845	11,414	8,842	6,869
TOTAL PROVED	341,376	302,826	260,659	227,529	202,052
PROBABLE	204,948	123,116	83,678	61,271	47,104
TOTAL PROVED PLUS PROBABLE	546,325	425,942	344,337	288,800	249,156

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS [1][2]

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Total Proved	1,037,677	107,977	508,505	20,103	25,297	375,794	34,418	341,376
Total Proved plus Probable	1,676,960	187,661	790,269	38,344	28,346	632,341	86,016	546,325

Notes:

(1) Total revenue includes company revenue before royalty and includes other income.
(2) Royalties include Crown, freehold and overriding royalties and mineral tax.

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 (discounted at 10%/year) ($000s)	UNIT VALUE [1] ($/Boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	135,604	24.73
	Heavy Oil (including solution gas and associated by-products)	144,083	23.80
	Natural Gas (including associated by-products)	5,189	7.55
	Total	284,876	23.30
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	202,853	22.39
	Heavy Oil (including solution gas and associated by-products)	185,418	21.72
	Natural Gas (including associated by-products)	7,007	6.57
	Total	395,278	21.18

Note:
(1) Unit values are based on net reserve volumes.

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "*Reserves Data (Forecast Prices and Costs)*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. **Gross** means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

   (b) in relation to wells, the total number of wells in which we have an interest; and

   (c) in relation to properties, the total area of properties in which we have an interest.

2. **Net** means:

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

   (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

   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:

   (a) analysis of drilling, geological, geophysical and engineering data;

   (b) the use of established technology; and

   (c) specified economic conditions (see the discussion of "Economic Assumptions" below).

   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.

4. **Economic Assumptions** are the forecast prices and costs used in the estimate.

   Development and Production Status

   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 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

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

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

5. **Exploratory well** means a well that is not a development well, a service well or a stratigraphic test well.

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

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

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

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

(d) provide improved recovery systems.

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

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

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

9. **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.

10. **Forecast Prices and Costs**

These are prices and costs that are:

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

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

11. Numbers may not add due to rounding.

12. The estimates of future net revenue presented in the tables above do not represent fair market value.

13. We do not have any synthetic oil or other products from non-conventional oil and gas activities.

Pricing Assumptions

The forecast cost and price assumptions in this Annual Information Form assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the Sproule Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

FORECAST PRICES AND COSTS (1)

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS			
Year	**WTI Cushing Oklahoma ($US/Bbl)**	**Edmonton Par Price 40° API ($Cdn/ Bbl)**	**Hardisty Bow River 25° API ($Cdn/ Bbl)**	**Hardisty Heavy 12° API ($Cdn/ Bbl)**	**AECO Gas Price ($Cdn/ MMbtu)**	**Edmonton Propane ($Cdn/Bbl)**	**Edmonton Butane ($Cdn/Bbl)**	**INFLATION RATES %/Year (2)**	**EXCHANGE RATE ($US/$Cdn) (3)**
Forecast									
2014	94.65	92.64	78.74	70.40	4.00	45.78	69.05	1.5	0.94
2015	88.37	89.31	75.92	67.88	3.99	44.14	66.57	1.5	0.94
2016	84.25	89.63	76.19	68.12	4.00	44.30	66.81	1.5	0.94
2017	95.52	101.62	86.38	77.23	4.93	50.22	75.74	1.5	0.94
2018	96.96	103.14	87.67	78.39	5.01	50.98	76.88	1.5	0.94
2019	98.41	104.69	88.99	79.57	5.09	51.74	78.03	1.5	0.94
2020	99.89	106.26	90.32	80.76	5.18	52.52	79.20	1.5	0.94
2021	101.38	107.86	91.68	81.97	5.26	53.30	80.39	1.5	0.94
2022	102.91	109.47	93.05	83.20	5.35	54.10	81.60	1.5	0.94
2023	104.45	111.12	94.45	84.45	5.43	54.92	82.82	1.5	0.94
2024	106.02	112.78	95.86	85.71	5.52	55.74	84.06	1.5	0.94
Thereafter			Escalation Rate of 1.5%						

Notes:

(1) December 31, 2013.
(2) Inflation rate for costs.
(3) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us for the year ended December 31, 2013, excluding price risk management activities, $69.51/Bbl for light and medium crude oil, $73.83 for heavy oil, were $3.03/Mcf for natural gas and $69.55/Bbl for NGLs.

Reserves Reconciliation

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)
December 31, 2012	93.4	149.4	242.8	2,589.0	684.6	3,273.6
Discoveries						
Extensions [(1)]	711.7	1217.3	1929.0			
Infill Drilling	9.1	2.8	11.9			
Improved Recovery						
Technical Revisions	(6.9)	(7.9)	(14.8)	(169.9)	(109.4)	(279.3)
Acquisitions [(2)]	4601.2	2171.0	6772.2	4420.4	2055.2	6475.6
Dispositions						
Economic Factors	1.9	2.9	4.8	43.1	26.2	69.3
Production	(45.3)	-	(45.3)	(436.1)	-	(436.1)
December 31, 2013	5,365.1	3,535.5	8,900.6	6,446.5	2,656.6	9,103.1

	ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbls)	Gross Probable (Mbbls)	Gross Proved Plus Probable (Mbbls)
December 31, 2012	-	-	-	-	-	-
Discoveries						
Extensions [(1)]	834	1,349	2,183	13.2	22.7	35.9
Infill Drilling						
Improved Recovery						
Technical Revisions						
Acquisitions [(2)]	10,511	5,709	16,220	52.3	24.2	76.5
Dispositions						
Economic Factors						
Production	(116)	-	(116)	(0.7)	-	(0.7)
December 31, 2013	11,229	7,058	18,287	64.8	46.9	111.7

Notes:

(1) Extensions also includes new reserve additions on acquired properties, not previously evaluated as reserve additions on our assets as of yearend 2012.

(2) Revisions associated with acquired properties have been reflected as part of the acquired reserves as of December 31, 2013. In accordance with the requirements of NI 51-101, the reserve estimates for the acquired properties are the reserves as of the effective date of the Sproule Report (December 31, 2013) plus production from the acquisition date.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In some cases, it will take longer than two years to develop these reserves. We plan to develop a significant majority of the proved and probable reserves in the Sproule Report over the next two years. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

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

Year	**Light and Medium Oil (Mbbls)**		**Heavy Oil (Mbbls)**		**Natural Gas (MMcf)**		**NGLs (Mbbls)**	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior	-	-	-	-	-	-	-	-
2012	27.2	27.2	-	-	-	-	-	-
2013	704.0	730.7	-	208.0	774	831	13.2	13.2

The majority of our proved undeveloped reserves evaluated in the Sproule Report are attributable to our Alderson, Jenner and Loverna properties. Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. Sproule has assigned 1.1 MMboe of proved undeveloped reserves in the Sproule Report with $19.8 million of associated undiscounted capital, of which $17.6 million is forecast to be spent in the first 2 years.

Probable Undeveloped Reserves

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

Year	**Light and Medium Oil (Mbbls)**		**Heavy Oil (Mbbls)**		**Natural Gas (MMcf)**		**NGLs (Mbbls)**	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior	-	-	-	-	-	-	-	-
2012	127.9	127.9	-	-	-	-	-	-
2013	1,213.7	1,338.7	-	133.7	1,335	1,372	22.7	22.7

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. Sproule has assigned 1.7 MMboe of probable undeveloped reserves in the Sproule report with $18.2 million of associated undiscounted capital, all of which is forecast to be spent in the first 2 years.

Significant Factors or Uncertainties

We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Future Development Costs

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

	FORECAST PRICES AND COSTS	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2014	13,699	31,940
2015	4,147	4,147
2016	2,258	2,258
2017	-	-
2018	-	-
Remaining	-	-
Total (Undiscounted)	20,103	38,344

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves could have a negative impact on our future cash flow.

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

Other Oil and Natural Gas Information

Principal Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2013. Information in respect of current production is average production, net to our working interest, except where otherwise indicated. Cardinal operates approximately 90% of its production. **The estimates of reserves for individual properties may not reflect the same confidence lever as estimates of reserves and future net revenue for all properties due to the effects of aggregation.**

Bantry (Alderson), Alberta

Bantry is located near Brooks, Alberta. The property produces medium crude oil, natural gas and natural gas liquids. The area's current base production, excluding production from drilling and including the acquisitions in the first quarter, is approximately 3,550 Boe/d with 86% of the production being crude oil.

The property is characterized by a low decline of less than 15% per year and a stable production profile. As at December 31, 2013, the property has 514 gross (426 net**)** producing oil wells and 81 gross (75 net) injection wells.

The majority of the oil production is from the Lower Mannville Ellerslie formation. The primary controlling factor for the deposition of the Ellerslie sandstone was the pre-cretaceous unconformity surface. The Mannville "A" Ellerslie sandstone has been deposited within a valley on the unconformity surface during a major transgressive sequence. The trapping mechanism for the pool is stratigraphic in nature and as porosity diminishes toward the up dip edge of the pool. The pools have been developed to date with vertical production and injection wells. The majority of the producing oil reservoirs on the lands are maintained by waterflood and/or water disposal. We have identified areas where we can optimize the existing waterflood to enhance oil recoveries. New drilling locations have also been identified in the Middle and Upper Mannville Channel sandstone deposits within the Bantry area. There is existing medium quality oil production from the identified channels currently being developed on nearby acreage. The channel sand currently produces in vertical wells on our lands and nearby acreage. We have identified horizontal drilling locations on the lands. Six oil processing facilities process the oil and natural gas production.

Jenner, Alberta

The Jenner property is located 60 kilometres northwest of Medicine Hat, Alberta. The property produces 1,430 boe/d day of heavy oil (11° API) and associated gas from the Mannville formation. As at December 31, 2013, the property has 117 gross (116 net) producing wells and 28 gross and net injection wells.

The Jenner properties primarily produce from the Upper Mannville Glauconitic sandstone which was deposited in an estuarine environment. The sands were originally believed to be Glauconite Channel sands likely due to thickness of the deposit of up to 50 meters. Recent geological studies indicate these are massive barrier beach deposits oriented in a north south direction for distances of up to 50 kilometres. These Glauconite age beach sands are also observed to repeat themselves as the ancient sea transgressed in an easterly direction. The reservoir sand exhibits a coarsening upward sequence typical of an estuarine beach deposit. Tidal channels passing transversally through these beaches helped to define these pools that exist today in the Jenner and Suffield areas. Subsequent to the sand deposition, the estuary was flooded as sea level rose and filled with a fine grained non porous silty sand which provides the trapping mechanism on the top and flanks of the reservoir.

Chauvin, Alberta

Chauvin is located approximately 65 kilometres east of Wainwright, Alberta. The assets consist of a 98% average working interest in 20° API oil with 100% of reserves being proved plus probable producing reserves. Production from the area is 100% oil production with a low decline of 15% per year. Current production from this area is approximately 870 Bbls/d.

Chauvin was acquired for its low decline medium gravity oil production. In the Chauvin area, production is primarily from the Middle Mannville sequence dominated by lower shore face marine sediments. The Sparky, General Petroleum, Rex and Lloydminster formations all currently produce oil on our lands in the area. These sands are all contained within the mid Mannville sequence where deposition was controlled by the topography of the sub-Cretaceous unconformity, changes in sea level and the regional sediment supply. The Sparky, General Petroleum, and Lloydminster are all characterized as lower shore face marine sediments. These formations all exhibit well sorted, wave dominated, coarsening upward sequences which were deposited in a marine shore face environment. The Rex sandstone in Chauvin is deposited as a channel facies which often exhibits varying degrees of reservoir quality. The Rex sandstone currently produces oil from vertical wells on our lands. Further upside exists in the exploitation of the Rex sandstone by drilling horizontally into existing pools, which will increase daily productivity and overall oil recovery. Many of the existing producing oil pools on our lands are currently being waterflooded to increase the ultimate oil recovery.

The property has 111 gross (110 net) vertical producing oil wells and 52 gross (51.5 net) injection wells. The oil well effluent is pipeline connected to four oil processing facilities. The oil is pipeline connected for sales although the clean oil may be trucked from time to time to optimize pricing. The produced water is injected into the producing formation as enhanced waterflood and disposal schemes.

Wainwright, Alberta

These properties were acquired on January 23, 2013 and produce approximately 115 Boe/d of medium quality crude oil (22° API) and associated gas. Crude oil makes up 99% of the production. The Wainwright Assets consist of 66% average working interest in medium quality crude oil assets located in the Wainwright area of Alberta with 100% of the reserves being proved plus probable producing reserves. Production from the Wainwright Assets has a low decline of 8% per year. We believe that the area has drilling upside and consolidation opportunities. We have 55 gross (37.5) net producing oil wells and 8 gross (5.7 net) injection wells in the area. Production is pipelined to one of three processing facilities in the area and is trucked to market. Water is injected in the producing reservoir for enhanced waterflood recovery.

Loverna, Saskatchewan / Hudson, Alberta

Loverna is located approximately 80 kilometres west of Kerrobert, Saskatchewan, straddling the Alberta and Saskatchewan border. Our operated wells produce oil from the Late Albian Viking formation which is a rare example of an ancient marine deposit that can be traced across the entire foreland basin. The Viking in this area produces light oil from both vertical and horizontal wells. We will continue to deploy horizontal drilling and multi-stage fracture technology to increase recovery factors from the identified pools. We have drilled 5 gross (4.5 net)] horizontal wells and have no further capital commitments in the area. Production from the area is approximately 30 Bbls/d. We have 28 sections of undeveloped land on the play.

The Loverna wells produce to single well batteries with no gas conservation. The oil well effluent is trucked to a third party for processing, oil sales and water disposal.

Oil And Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2013.

	OIL WELLS				**NATURAL GAS WELLS**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	670	612	344	312	153	87	101	71
Saskatchewan	6	6	8	6	-	-	1	1
Total	676	618	352	318	153	87	102	72

Note:

(1) Does not include 220 gross (199 net) service wells.

Of the non-producing wells, one well drilled in 2013 was capable of production and had reserves assigned to it. As of the date of this Annual Information Form, this well had not yet been placed on production.

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2013.

	UNDEVELOPED ACRES		**DEVELOPED ACRES**		**TOTAL ACRES**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	100,141	78,092	85,107	69,258	185,248	147,350
Saskatchewan	2,849	2,677	1,295	1,157	4,144	3,384
Total	102,990	80,769	86,402	70,415	189,392	151,184

Rights to explore, develop and exploit 41 net acres of these undeveloped land holdings could expire by December 31, 2014 if not continued.

When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Forward Contracts

Our operational results and financial condition will be dependent upon the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely in recent years. Such prices are primarily determined by economic and political factors, supply and demand factors, as well as weather and conditions in other oil and natural gas regions of the world also impact prices. Any upward or downward movement in oil and natural gas prices could have an effect on our financial condition.

We have implemented a hedging policy using, amongst others, collars and fixed price swaps to hedge our gross oil, NGLs and natural gas production up to 60% for the current year, up to 40% for the following year and up to 30% the next following year for a maximum period of 3 years. These hedging activities could expose us to losses or gains. See "*Risk Factors - Hedging*".

For further information, see notes 13 and 19 to our financial statements for the year ended December 31, 2013.

Additional Information Concerning Abandonment and Reclamation Costs

We estimate the costs to abandon and reclaim all our non-producing and producing wells, gas plants, pipelines, batteries, and other facilities. No estimate of salvage value is netted against the estimated cost. Our model for estimating the amount of future abandonment and reclamation expenditures is done on an individual well and facility level. Each well and facility is assigned an average cost for abandonment and reclamation over its useful life. Timing of expenditures is based on budgets and estimates of such annual activities. Facility reclamation costs are generally scheduled to begin shortly before the end of the reserve life of our associated reserves and continue beyond the reserve life under the assumption that plant/facilities are generally mobile assets with a long useful life.

As at December 31, 2013 we had 1,294 net wells for which we expect to incur abandonment and reclamation costs.

The total amount of abandonment and reclamation costs that we expect to incur are summarized in the following table:

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($000s)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($000s)
Total liability as at December 31, 2013	192,850	27,762
Anticipated to be paid in 2014	463	442
Anticipated to be paid in 2015	62	52
Anticipated to be paid in 2016	-	-

The future net revenues disclosed in this Annual Information Form are based on the Sproule Report and do not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. In estimating the future net revenues disclosed in this Annual Information Form, the Sproule Report only deducted $28.3 million (undiscounted) and $8.0 million (10% discount) for abandonment costs of wells with proved and probable reserves.

Tax Horizon

Based on estimated 2014 cash flow and capital expenditures, we do not expect to be cash taxable until 2015.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2013.

Expenditure	Year Ended December 31, 2013 ($000s)
Property acquisition costs – Unproved properties [(1)]	2,885
Property acquisition costs – Proved properties [(2)]	282,438
Exploration costs [(3)]	107
Development costs [(4)]	6,127
Total	291,557

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Net of dispositions.
(3) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(4) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.
(5) Expenditures do not include capitalized general and administrative costs and related share based compensation or non-cash expenditures for the decommissioning obligation.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2013.

	Development		Exploratory	
	Gross	Net	Gross	Net
Natural Gas	1.0	1.0	-	-
Light and Medium Oil	2.0	1.5	-	-
Dry	-	-	-	-
Total	3.0	2.5	-	-

In 2014, we expect to drill approximately 12.9 net oil wells in Alberta and 5 net oil wells in Saskatchewan.

Finding and Development Costs

The following table summarizes our finding and development costs for the periods indicated.

($/Boe) [(1)(2)(3)(6)]	2013	2012
Proved Reserves		
Finding, development and acquisition cost	22.27	22.45
Finding and development costs [(4)]	25.68	13.44
Acquisition costs [(5)]	22.03	23.84
Proved plus Probable Reserves		
Finding, development and acquisition cost	14.99	18.99
Finding and development costs [(4)]	15.77	16.56
Acquisition costs [(5)]	14.88	19.39

Notes:

(1) Including changes in future development capital expenditures.
(2) We have presented finding and development costs both including and excluding acquisitions and dispositions. While NI 51-101 requires that the effects of acquisitions and dispositions be excluded, we have included these items because we believe that acquisitions and dispositions can have a significant impact on our ongoing reserve replacement costs and that excluding these amounts could result in an inaccurate portrayal of our cost structure.

(3) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital expenditures generally will not reflect total finding and development costs related to reserves additions for that year.

(4) Finding and development costs, include new additions on acquired properties, not previously evaluated, as well as additions on our assets as of December 31, 2012.

(5) Revisions associated with acquired properties have been reflected as part of the acquired reserves as of December 31, 2013. As per the requirements of NI 51-101, the reserve estimates for the acquired properties are the reserves as of the effective date of the Sproule Report (December 31, 2013) plus the production from the acquisition date.

(6) Finding and development costs exclude capital related to fair value adjustments on acquisitions and non-cash expenditures for the decommissioning obligation.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2014, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Disclosure of Reserves Data*".

	Light and Medium Oil (Bbls/d)	**Heavy Oil (Bbls/d)**	**Natural Gas (Mcf/d)**	**Natural Gas Liquids (Bbls/d)**	**BOE (Boe/d)**
Total Proved					
Bantry (Alderson), Alberta	1,960	473	2,673	19	2,898
Jenner, Alberta	-	1,174	802	-	1,308
Chauvin, Alberta	-	831			831
Wainwright, Alberta	-	111	1	-	111
Loverna, Saskatchewan/Hudson, Alberta	35	-	26	-	39
Other	445	146	1036	9	773
Total	2,440	2,735	4,538	28	5,960
Total Proved plus Probable					
Bantry (Alderson), Alberta	2,315	474	3,041	25	3,321
Jenner, Alberta	-	1,214	825	-	1,351
Chauvin, Alberta	-	838	-	-	838
Wainwright, Alberta	-	114	5	-	114
Loverna, Saskatchewan/Hudson, Alberta	82	-	26	-	86
Other	454	150	1,059	10	791
Total	2,851	2,790	4,956	35	6,501

Production History

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

	Quarter Ended 2013				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31 [(4)]**	**Dec. 31, 2013**
Average Daily Production [(1)]					
Light and Medium Oil (bbls/d)	45	41	50	358	124
Heavy Oil	1,084	1,043	1,049	1,599	1,195
Natural Gas Liquids	-	-	-	8	2
Gas (Mcf/d)	27	23	71	1,139	317
Combined (boe/d)	1,133	1,087	1,111	2,155	1,374
Average Prices Received					
Light and Medium Oil ($/bbl)	73.88	86.33	101.97	62.58	69.51
Heavy Oil	63.42	77.24	91.86	66.70	73.83
Natural Gas Liquids	-	-	-	69.55	69.55
Gas ($/Mcf)	2.57	3.52	2.72	3.05	3.03
Combined ($/boe)	63.65	77.39	91.51	61.76	71.29
Royalties Paid					
Light and Medium Oil ($/bbl)	6.98	3.78	5.98	4.80	5.03
Heavy Oil	7.45	8.17	10.49	10.47	9.30
Natural Gas Liquids	-	-	-	12.47	12.47
Gas ($/Mcf)	0.15	0.20	0.28	0.71	0.66
Combined ($/boe)	7.41	7.98	10.19	8.98	8.71
Production Costs [(2)(3)]					
Light and Medium Oil ($/bbl)	30.09	31.30	19.48	49.60	43.31
Heavy Oil	21.61	27.89	33.43	27.31	27.52
Natural Gas Liquids	-	-	-	2.02	2.02
Gas ($/Mcf)	0.02	0.03	0.04	0.37	0.34
Combined ($/boe)	21.87	27.93	32.45	28.72	27.93
Netback Received					
Light and Medium Oil ($/bbl)	36.81	51.25	76.51	8.18	21.17
Heavy Oil	34.36	41.18	47.94	28.92	37.01
Natural Gas Liquids	-	-	-	55.06	55.06
Gas ($/Mcf)	2.40	3.29	2.40	1.97	2.03
Combined ($/boe)	34.37	41.48	48.87	24.06	34.65

Notes:

(1) Before the deduction of royalties.

(2) Production costs are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between product types.

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

(4) The average prices received for light and medium oil, production costs and resulting netbacks reflect only 14 days of production from the acquisition of the SE Alberta Assets.

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2013.

	Crude Oil (Bbls/d)	Natural Gas Liquids (Bbls/d)	Natural Gas (Mcf/d)	BOE (Boe/d)
Chauvin	925	-	-	925
Bantry (Alderson)	166	2	246	208
Wainwright	117	-	24	121
Jenner	53	-	11	55
Loverna/Hudson	40	-	-	40
Other	19	-	36	25
Total	1,319	2	317	1,374

DESCRIPTION OF OUR CAPITAL STRUCTURE

Share Capital

We are authorized to issue and unlimited number of Common Shares without nominal or par value and an unlimited number of first preferred shares. A description of our share capital is set forth below. For a completed description of our share capital, reference should be made to our Articles, a copy of which has been filed on SEDAR at www.sedar.com.

Common Shares

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

Voting Rights: Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of our Shareholders (other than meetings of a class or series of shares other than our Common Shares).

Dividends: Holders of Common Shares are entitled to receive dividends as and when declared by our Board of Directors on the Common Shares as a class, subject to the prior satisfaction of all preferential rights to dividends attached to other classes of shares ranking in priority to the Common Shares in respect of dividends.

Ranking: In the event of any liquidation, dissolution or winding-up of us, whether voluntary or involuntary, or any other distribution of our assets among our Shareholders for the purpose of winding-up our affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all other classes of Shares ranking in priority to the Common Shares in respect of return of capital on dissolution, holders of Common Shares are entitled to share rateably, together with the holders of shares of any other class of shares ranking equally with the Common Shares, in respect of a return of capital on dissolution, in such of our assets as are available for distribution.

If our Board of Directors declare a dividend on the Common Shares payable in whole or in part in fully paid and non-assessable Common Shares (the portion of the dividend payable in Common Shares referred to as a "stock dividend"), the following provisions shall apply:

(a) unless otherwise determined by the Board of Directors in respect of a particular stock dividend: (i) the number of Common Shares (which shall include any fractional Common Shares) to be issued in satisfaction of the stock dividend shall be determined by dividing (A) the dollar amount of the particular stock dividend, by (B) the "Average Market Price" of a Common Share on the Toronto Stock Exchange, with the "Average Market Price" calculated by dividing the total value of Common Shares traded on the Toronto Stock Exchange (or if the Common Shares are not traded on the Toronto Stock Exchange, on any other recognized exchange or market on which the Common Shares are traded) by the total volume of Common Shares traded on the Toronto Stock Exchange (or if the Common Shares are not traded on the Toronto Stock Exchange, on any other recognized exchange or market on which the Common Shares are traded) over the five trading day period immediately prior to the payment date of the applicable stock dividend on the Common Shares; and (ii) the value of a Common Share to be issued for the purposes of each stock dividend declared by the Board of Directors shall be deemed to be the Average Market Price of a Common Share;

(b) to the extent that any stock dividend paid on the Common Shares represents one or more whole Common Shares payable to a registered holder of Common Shares, such whole Common Shares shall be registered in the name of such holder. Common Shares representing in the aggregate all of the fractions amounting to less than one whole Common Share which might otherwise have been payable to registered holders of Common Shares by reason of such stock dividend shall be issued to our transfer agent as the agent of such registered holders of Common Shares. Our transfer agent shall credit to an account for each such registered holder all fractions of a Common Share amounting to less than one whole share issued by us by way of stock dividends in respect of the Common Shares registered in the name of such holder. From time to time, when the fractional interests in a Common Share held by our transfer agent for the account of any registered holder of Common Shares are equal to or exceed in the aggregate one additional whole Common Share, the transfer agent shall cause such additional whole Common Share to be registered in the name of such registered holder and thereupon only the excess fractional interest, if any, will continue to be held by the transfer agent for the account of such registered holder. Common Shares held by the transfer agent representing fractional interests shall not be voted;

(c) if at any time we have reason to believe that tax should be withheld and remitted to a taxation authority in respect of any stock dividend paid or payable to a Shareholder in Common Shares, we have the right to sell, or to require our transfer agent in each case as agent of such Shareholder, to sell all or any part of the Common Shares or any fraction thereof so issued to such holder in payment of that stock dividend or one or more subsequent stock dividends through the facilities of the Toronto Stock Exchange or other stock exchange on which the Common Shares are listed for trading, and to cause its transfer agent to remit the cash proceeds from such sale to such taxation authority (rather than such holder) in payment of such tax to be withheld. This right of sale may be exercised by notice given by us to such holder and to us or our transfer agent stating the name of the holder, the number of Common Shares to be sold and the amount of the tax which we have reason to believe should be withheld. Upon receipt of such notice the transfer agent shall, unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and the Company or its transfer agent as applicable, shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and deliver the proceeds therefrom to the applicable taxation authority on behalf of us. Any balance of the cash sale proceeds not remitted by us in payment of the tax to be withheld shall be payable to the holder whose Common Shares were so sold by the transfer agent;

(d) if at any time we shall have reason to believe that the payment of a stock dividend to any holder who is resident in or otherwise subject to the laws of a jurisdiction outside Canada might contravene the laws or regulations of such jurisdiction, or could subject us to any penalty thereunder or any legal or regulatory requirements not otherwise applicable to us, we shall have the right to sell, or to require our transfer agent in each case, as agent of such Shareholder, to sell through the facilities of the Toronto Stock Exchange or other stock exchange on which the Common Shares are listed for trading, the Common Shares or any fraction thereof so issued and to cause our transfer agent to pay the cash proceeds from such sale to such holder. The right of sale shall be exercised in the manner provided in subparagraph (c) above except that in the notice there shall be stated, instead of the amount of the tax to be withheld, the nature of the law or regulation which might be contravened or which might subject us to any penalty or legal or regulatory requirement. Upon receipt of the notice, we or our transfer agent shall, unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and we or our transfer agent, as applicable, shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and to deliver the proceeds therefrom to such holder;

(e) upon any registered holder of Common Shares ceasing to be a registered holder of one or more Common Shares, such holder shall be entitled to receive from our transfer agent, and the transfer agent shall pay as soon as practicable to such holder, an amount in cash equal to the proportion of the value of one Common Share that is represented by the fraction less than one whole Common Share at that time held by our transfer agent for the account of such holder and, for the purpose of determining such value, each Common Share shall be deemed to have the value equal to the Average Market Price in respect of the last stock dividend paid by us prior to the date of such payment; and

(f) for the purposes of the foregoing: (i) the calculation of a fraction of a Common Share payable to a Shareholder by way of a stock dividend and the calculation of the Average Market Price shall be computed to six decimal places, and shall be rounded to the nearest sixth decimal place; and (ii) neither us nor our transfer agent shall have any obligation to register any Common Share in the name of a person, to deliver a certificate or other document representing Common Shares registered in the name of a Shareholder or to make a cash payment for fractions of a Common Share, unless all applicable laws and regulations to which we and/or our transfer agent are, or as a result of such action may become, subject, shall have been complied with to their reasonable satisfaction.

First Preferred Shares

Voting Rights: Holders of first preferred shares shall be entitled to receive notice of, to attend and to one vote per first preferred share held at any meeting of the Shareholders (other than meetings of a class or series of shares of Cardinal other than the first preferred shares as such).

Dividends: Holders of first preferred shares shall be entitled to receive if, as and when declared by our Board of Directors out of the monies of our applicable to the payment of dividends, such dividends in any financial year as the Board of Directors in its absolute discretion may by resolution determine, and the directors may, subject to certain restrictions on dividends, declare dividends on any other class of share at different times or at the same time in different amounts than dividends declared on the first preferred shares.

Ranking: In the event of the liquidation, dissolution or winding up of us or other distribution of our assets among Shareholders for the purpose of winding up our affairs, the holders of first preferred shares shall be entitled to receive the redemption value of the first preferred shares per share, together with any accrued and unpaid dividends thereon up to the date of commencement of any such liquidation, dissolution, winding up or other distribution of our assets and to be paid all such money before any money shall be paid or property or assets distributed to the holders of any Common Shares or other shares in our capital ranking junior to the first preferred shares with respect to return of capital. After payment to the holders of the first preferred shares of the amounts so payable to them in accordance, the holders of first preferred shares shall not be entitled to share in any further distribution of our property or assets.

Credit Facility

The Credit Facility is a syndicated facility comprised of a $115 million syndicated borrowing base credit facility and a $10 million operating credit facility. The Credit Facility has a 364 day revolving period and the option, at our request and with the consent of the lenders, to be extended on an annual basis. If not extended, the Credit Facility will automatically convert to a one year non-revolving term loan and all obligations under the Credit Facility will be required to be repaid at the end of the one-year period. The initial revolving period is May 30, 2014. As security for the provision of the Credit Facility, we have provided the lenders a debenture securing a first floating charge on all of our present and after acquired property. See "*Risk Factors – Credit Facility Risk*".

MARKET FOR OUR SECURITIES

Our Common Shares trade on the Toronto Stock Exchange under the trading symbol "CJ" and commenced trading on the Toronto Stock Exchange on December 17, 2013.

The following sets out the high and low trading prices and aggregate volume of trading for the periods noted below for our Common Shares:

Period	High	Low	Volume
2013			
December (17-31)	12.05	11.10	8,452,092
2014			
January	13.50	11.50	7,256,246
February	13.37	12.29	4,152,794
March (to March 27)	14.75	13.06	1,888,272

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

The following table sets forth, as of the date of this Annual Information Form, the number of Common Shares or securities held, to our knowledge, in escrow or that is subject to a contractual restriction on transfer and the percentage that number represents of the outstanding securities of that class.

Designation of Class	Number of Securities Held in Escrow (1)(2)	Percentage of Class
Common Shares	3,883,736	10.3%

Note:

(1) Every officer, director, employee and certain other Shareholders delivered us with an undertaking pursuant to which, subject to certain exceptions, they have agreed not to, directly or indirectly, offer, sell, contract to sell, lend, swap or enter into any other agreement to dispose of any Common Shares or other of our securities they hold and which were acquired at a subscription price equal to $3.00 per Common Share until December 31, 2014.

(2) In addition pursuant to the underwriting agreement we entered into in connection with our initial public offering, each of our directors and officers have provided an undertaking to the underwriters, pursuant to which they have agreed not to offer to sell, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any Common Shares held by them until December 31, 2014 without the prior written consent of the lead underwriters.

DIRECTORS AND OFFICERS

Summary Information

The following table sets forth certain summary information in respect of our directors and executive officers as at the date of this Annual Information Form.

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since	Common Share Ownership [5]
M. Scott Ratushny [2][3] Alberta, Canada	Chief Executive Officer and Chairman	Chief Executive Officer of Cardinal since July 6, 2012. Prior thereto, Chairman and Chief Executive Officer of Midway Energy Ltd., an oil and gas company, from July, 2009 to May, 2012. Prior thereto Chairman and Chief Executive Officer of Pilot Energy from April 2004 to January 2008.	May 3, 2011	1,112,348
James C. Smith [1][3][4] Alberta, Canada	Director	Independent director and consultant to a number of public and private oil and gas companies.	July 9, 2012	152,500 [6]
David D. Johnson [1][2][3][4] Alberta, Canada	Director	Independent Businessman. Mr. David D. Johnson was the Chairman of Progress Energy Resources Corp. prior to its sale on December 12, 2012. From 2004 to 2009, Mr. Johnson served as the Chairman of Progress Energy Trust and was President and Chief Executive Officer of ProEx Energy Ltd.	July 9, 2012	276,389 [6]
John A. Brussa [2] Alberta, Canada	Director	Mr. Brussa has been a partner of Burnet, Duckworth & Palmer LLP since 1987 and is presently the head of its Tax Department.	July 9, 2012	486,555
Gregory T. Tisdale [1][2][4] Alberta, Canada	Director	Mr. Tisdale is the Chief Financial Officer of Crescent Point Energy Ltd., a public oil and gas company, and has held this position since October of 2004.	January 7, 2014	12,500
Shane Peet Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Cardinal since July 6, 2012. Prior thereto, Chief Operating Officer of Midway Energy Ltd., an oil and gas company, from February, 2011 to May, 2012. Prior thereto, Senior Vice President Engineering of Equal Energy Ltd. from July 2009 to February 2011, prior thereto, Chief Operating Officer of Wild River Resources Ltd. from October 2007 to June 2009.	N/A	826,867
Douglas Smith Alberta, Canada	Chief Financial Officer	Chief Financial Officer since July 6, 2012. Prior thereto Chief Financial Officer of Midway Energy Ltd. from July 2009 to May 2012, prior thereto Mr. Smith was the Chief Financial Officer of Pilot Energy from April 2004 to January 2008.	N/A	329,267
Craig Kolochuk Alberta, Canada	Vice President, Land	Vice President Land since July, 2012. Prior thereto, Land Manager of Midway Energy Ltd. (a public oil and gas company) from August 2010 to May 2012, prior thereto Mr. Kolochuk was the Land Manager of WestFire Energy Ltd. from September 2008 until August 2010.	N/A	373,867 [6]

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since	Common Share Ownership [5]
Timothy Hyde Alberta, Canada	Vice President, Exploration	Vice President, Exploration since July 31, 2012. Prior thereto, Consulting Technical Advisor to Livingstone Energy Management (a private equity firm affiliated with Lime Rock Partners) from Sept 2008 to Jan 2011.	N/A	298,333 [6]

Notes:

(1) Member of our Audit Committee. Mr. James C. Smith is the chairman of the Audit Committee.
(2) Member of our Governance & Compensation Committee. Mr. John A. Brussa is the Chairman of the Governance & Compensation Committee.
(3) Member of the Reserves Committee. Mr. David D. Johnson is the Chairman of the Reserves Committee.
(4) Independent director.
(5) Represents Common Shares and other securities beneficially owned, controlled or directed (directly or indirectly) by the director or officer as of the date hereof based on information provided by such individuals.
(6) Includes Common Shares held by Messrs Johnson, Smith, Hyde and Kolochuk's spouse and/or children.

All of our directors' terms of office will expire at the earliest of their resignation, the close of the next annual shareholder meeting called for the election of directors, or on such other date as they may be removed according to the *Business Corporations Act* (Alberta). Each director will devote the amount of time as is required to fulfill his obligations to us. Our officers are appointed by and serve at the discretion of the Board of Directors.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this prospectus, or was within ten years before the date of this prospectus, a director, chief executive officer or chief financial officer of any company (including us), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

To our knowledge none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially our control: (a) is, as of the date of this prospectus, or has been within the ten years before the date of this prospectus, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this prospectus, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or Shareholder.

Penalties or Sanctions

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially our control has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

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

AUDIT COMMITTEE

Audit Committee Mandate

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

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee consists of Messrs. Smith (Chair), Tisdale and Johnson. Each of the members of the Audit Committee is considered "financially literate" and "independent" within the meaning of National Instrument 52-110 – *Audit Committees*.

We believe that each of the members of the Audit Committee possesses: (a) an understanding of the accounting principles used by us to prepare its financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by our financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting. The relevant education and experience of each audit committee member is outlined below:

James C. Smith:

Mr. Smith is a Chartered Accountant with over 40 years of experience in public accounting and industry. While Mr. Smith was the Vice President and Chief Financial Officer of Crestar Energy Inc. from its inception in 1992 until 1998, the company completed an initial public offering, was listed on the Toronto Stock Exchange and completed several major debt and equity financing transactions. From 1998 to 2006, he was a business consultant to a number of public and private companies operating in the oil and gas industry. Since 2004 he has been a director and audit committee chairman for a number of public and private companies.

Greg Tisdale:

Mr. Tisdale has held the position of Chief Financial Officer of Crescent Point Energy Ltd. since October 2004. During the past ten years he has managed all aspects of Crescent Point's finances. Mr. Tisdale has worked in the oil and gas industry since 1995 and has served and currently serves on the board of directors of several junior oil and gas companies. Mr. Tisdale holds a Bachelor of Commerce degree (with distinction) from the University of Alberta and is a Chartered Accountant.

David D. Johnson:

Mr. Johnson has over 35 years of diverse experience in the oil and gas industry including a background in production, reservoir evaluation and operations. He has a B.Sc. in Petroleum Engineering, is a member of the Association of Professional Engineers and Geoscientists of Alberta and has served twice as a governor of the Canadian Association of Petroleum Producers.

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

The Audit Committee must pre-approve all non-audit services to be provided to us by our external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by the Audit Committee from time to time.

External Audit Service Fees

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

Year	Audit Fees (1)	Audit -Related Fees (2)	Tax Fees	All Other Fees (3)
	($)	($)	($)	($)
2012	30,000	22,000	N/A	N/A
2013	100,000	124,000	1,000	133,000

Notes:

(1) Represents the aggregate fees billed by KPMG LLP in the last fiscal year for audit services.
(2) Represents the aggregate fees billed by KPMG LLP for the property audit of the Chauvin #1 Assets in 2012 and the Chauvin #2 Assets, Loverna Assets, Bantry Assets and SE Alberta Assets in 2013.
(3) Includes $110,000 billed by KPMG LLP for our initial public offering.

Reliance on Exemptions

Other than as discussed below, at no time since the commencement of our most recently completed financial year have we relied on any of the exemptions contained in National Instrument 52-110 – Audit Committees with respect to independence or composition of our Audit Committee.

Prior to January 7, 2014, our Audit Committee did not include three "independent" directors within the meaning of National Instrument 52-110 – *Audit Committees* as Mr. Brussa was considered not independent due to the fact that he is a partner in a law firm that provides services to us. During such time the Board determined that we could rely on the exemption in section 3.2(2) of National Instrument 52-110 – *Audit Committees* available to us. The exemption in section 3.2(2) of National Instrument 52-110 – *Audit Committees* relieves an issuer for a period of up to one year after it becomes a reporting issuer from the requirement that every audit committee member be independent, provided that a majority of the audit committee members are independent and the issuer's board of directors makes the determination in the preceding sentence. On January 7, 2014, Mr. Tisdale was appointed to our

Board and he replaced Mr. Brussa on the Audit Committee, following which the composition of our Audit Committee is fully independent and we no longer need to rely on the exemption in section 3.2(2) of National Instrument 52-110 – *Audit Committees.*

Audit Committee Oversight

At no time since commencement to the most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by our Board of Directors.

DIVIDEND POLICY

Dividends and Dividend Policy

On January 7, 2014 our Board of Directors adopted a dividend policy of paying monthly dividends at a rate of $0.05417. See "*General Development of our Business – Recent Developments*". Our first dividend was declared for Shareholders of record on January 31, 2014 and paid on February 17, 2014.

We carefully monitor the impact of all issues affecting our business and the necessity to adjust our monthly dividends and our capital programs as conditions evolve.

The amount of future cash dividends, if any, will be in the sole discretion of the Board after considering a variety of factors and conditions existing from time to time, including current and future commodity prices, foreign exchange rates, our hedging program, current operations including production levels, operating costs, royalty burdens and debt service requirements, available investment opportunities and the satisfaction of the liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends.

Cash dividends are paid on the 15th day (or if such date is not a business day, on the next business day) following the end of each calendar month to Shareholders of record on the last business day of each such calendar month or such other date as determined from time to time by us.

Our long-term objective is to set a dividend policy at prudent levels while withholding sufficient funds to finance capital expenditures required to grow our current production base by a target of 5% to 10% annually. This in turn, is expected to provide a stronger base of cash flow leading to consistent dividends into the future.

We have implemented a dividend reinvestment plan which enables eligible Shareholders to reinvest their cash dividends into additional Common Shares which will be purchased through the facilities of the Toronto Stock Exchange at prevailing market prices or issued from treasury at 100 percent of the average market price (as defined in the plan) on the applicable dividend payment date. We have also activated our stock dividend program which enables us to issue Common Shares as payment of all or a portion of dividends declared on the Common Shares for those Shareholders who elect to receive stock dividends instead of cash dividends. See "*Description of our Capital Structure*".

Our Credit Facility contains restrictions on our ability to pay dividends in certain circumstances. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the *Business Corporations Act* (Alberta). Pursuant to the *Business Corporations Act* (Alberta), 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.

Cash dividends are not guaranteed. Although we intend to make dividends in the amount indicated to Shareholders, these cash dividends may be reduced or suspended. The actual amount distributed will depend on numerous 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 and the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends applicable law and other factors beyond our control. See "*Risk Factors*".

The following monthly cash dividends on Common Shares were declared by us for the periods indicated:

For the Month Ended	Dividends per Common Share	Payment Date
March 31, 2014	$0.05417	April 15, 2014
February 28, 2014	$0.05417	March 17, 2014
January 31, 2014	$0.05417	February 17, 2014

Unless otherwise specified, all dividends paid or to be paid by us are designated as "eligible dividends" under the *Income Tax Act* (Canada).

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 and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect our operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and we are 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 market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada. 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 National Energy Board. The National Energy Board 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. In this transitory period, the National Energy Board of Canada 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 also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the National Energy Board.

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

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

Alberta

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%

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 at Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 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 that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program 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 Innovative Energy Technologies Program 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 an Emerging Resource and Technologies Initiative intended to accelerate technological development and facilitate the development of unconventional resources. 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.

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil being "fourth tier oil", "third tier oil", "new oil" and "old oil" depends on the finished drilling date of a well and 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" applicable to that classification of oil. Currently the Production Tax Factor is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

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

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

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

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.** The current regulatory scheme provides for **c**ertain differences with respect to the administration of "fourth tier gas" which is associated gas.

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

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

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

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

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

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

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

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

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

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

Land Tenure

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

Each of the provinces of Alberta and Saskatchewan 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.

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 *Jobs, Growth and Long-term 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. Changes to the environmental legislation under the *Jobs, Growth and Long-term 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 assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act*. On November 30, 2013, the Alberta Energy Regulator assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the Alberta Energy Regulator is expected to assume the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The Alberta Energy Regulator'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 Alberta Land Use Framework 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* provides the legislative authority for the Government of Alberta to implement the policies contained in the Alberta Land Use Framework. Regional plans established under the *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* 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 which came into force on September 1, 2012. The Lower Athabasca Regional Plan is the first of seven regional plans developed under the Alberta Land Use Framework. The Lower Athabasca Regional Plan 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.

The Lower Athabasca Regional Plan 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 which covers approximately 83,764 square kilometres and includes 45 % of the provincial population. The South Saskatchewan Regional Plan 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 Alberta Energy Regulator, Alberta Environment and Sustainable Resource Development will remain responsible for development and implementation of regional plans. However, the Alberta Energy Regulator will take on some responsibility for implementing regional plans in respect of energy related activities.

Saskatchewan

In May 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act*, 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* and *The Petroleum Registry and Electronic Documents Regulations*. The aim of the amendments to the *Oil and Gas Conservation Act*, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the *The Petroleum Registry and Electronic Documents Regulations* and the *Oil and Gas Conservation Regulations, 2012*, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

In Alberta, the Alberta Energy Regulator implements the Licensee Liability Rating Program. The Licensee Liability Rating Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The *Oil and Gas Conservation Act* establishes an orphan fund to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the Licensee Liability Rating Program if a licensee or working interest participant becomes defunct. The orphan fund is funded by licensees in the Licensee Liability Rating Program through a levy administered by the Alberta Energy Regulator. The Licensee Liability Rating Program is designed to minimize the risk to the orphan fund posed by unfunded liability of licences and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The Licensee Liability Rating Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the Alberta Energy Regulator 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 Alberta Energy Regulator.

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

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

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

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

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

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

Saskatchewan

In Saskatchewan, the Ministry of Economy implements its own Licensee Liability Rating Program. The Saskatchewan Licensee Liability Rating 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 established under the *The Oil and Gas Conservation Act*. The Saskatchewan orphan fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the Licensee Liability Rating Program when a licensee or working interest partner is defunct or missing. The Saskatchewan Licensee Liability Rating Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Climate Change Regulation

Federal

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* and a participant to the Copenhagen Accord (a non-binding agreement created by the *United Nations Framework Convention on Climate Change* which represents a broad political consensus and reinforces commitments to reducing greenhouse gas emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of greenhouse gas 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" which set forth a plan for regulations to address both greenhouse gas 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 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 greenhouse gas 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 greenhouse gas 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 greenhouse gas emissions.

Alberta

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

As part of its efforts to reduce greenhouse gas emissions, Alberta introduced legislation to address greenhouse gas emissions: the *Climate Change and Emissions Management Act* 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 *Climate Change and Emissions Management Act* 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,* which imposes greenhouse gas limits, and the *Specified Gas Reporting Regulation*, which imposes greenhouse gas emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to compliance with the *Climate Change and Emissions Management Act*. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their greenhouse gas emissions.

The *Specified Gas Emitters Regulation*, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of greenhouse gases in 2003 or any subsequent year, and requires reductions in greenhouse gas emissions intensity (e.g. the quantity of greenhouse gas emissions per unit of production) from emissions intensity baselines established in accordance with the regulation. The regulation 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 regulation. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10% of their baseline in the eighth year. The *Climate Change and Emissions Management Act* does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

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

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

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* to regulate greenhouse gas emissions in the province. The act received Royal Assent on May 20, 2010 and will come into force on proclamation. The act establishes a framework for achieving the provincial target of a 20% reduction in greenhouse gas emissions from 2006 levels by 2020. The act and related regulations have yet to be proclaimed in force.

RISK FACTORS

An investment in our Common Shares is subject to various risks including those risks inherent to the industry in which we operate. If any of these risks occur, our production, revenues and financial condition could be materially harmed, with a resulting decrease in dividends on, and the market price of, the Common Shares. As a result, the trading price of our Common Shares could decline, and you could lose all or part of your investment. Cash dividends to Shareholders are not assured or guaranteed.

Before deciding whether to invest in any Common Shares, investors should consider carefully the risks set out below. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect our business, financial condition or results of operations.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering and processing facilities and pipeline systems some of which we do not own and by rail. The amount of oil and natural gas that we 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 our inability to realize the full economic potential of our production or in a reduction of the price offered for our 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 our business and, in turn, our financial condition, results of operations and cash flows.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

A portion of our production may, from time to time, be processed through facilities owned by third parties and over which we do 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 our ability to process our production and deliver the same for sale.

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. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able continue to find satisfactory properties to acquire or participate in. Moreover, management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that we will discover or acquire further commercial quantities of oil and natural gas.

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

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, we 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 for us.

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 our business, financial condition, results of operations and prospects.

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

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our 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 our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we 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 we produce effectively.

Prices, Markets and Marketing

Numerous factors beyond our control do, and will continue to, affect the marketability and price of oil and natural gas we acquire or discover. Our ability to market our oil and natural gas may depend upon our 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 our 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 us.

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 our control. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. A material decline in prices could result in a reduction our 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 our reserves. We might also elect not to produce from certain wells at lower prices.

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

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect us from commodity price declines, we 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, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

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

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

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

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 our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our 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).

Substantial Capital Requirements

We anticipate 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, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- our 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 our securities in particular.

Further, if our revenues or reserves decline, we 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 us. Our ability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Credit Facility Arrangements

The Credit Facility and the amount authorized thereunder are dependent on the borrowing base determined by its lenders. We are required to comply with covenants under the Credit Facility which include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facility, which could result in the requirement to repay amounts owing thereunder. Even if we are able to obtain new financing, it may not be on commercially reasonable terms or terms that we consider acceptable. If we are unable to repay amounts owing under the Credit Facility, the lenders could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facility may impose operating and financial restrictions that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our 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. See: "*Description of Our Capital Structure – Credit Facility*".

Our lenders use our reserves, commodity prices, applicable discount rate and other factors, to periodically determine our borrowing base. A material decline in commodity prices could reduce our borrowing base, reducing the funds available to us under the Credit Facility. This could result in the requirement to repay a portion, or all, of our bank indebtedness.

Additional Funding Requirements

Cash flow from our reserves may not be sufficient to fund our ongoing activities at all times and, from time to time, we may require additional financing in order to carry out our 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, our access to additional financing may be affected.

Because of global economic volatility, we 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 us to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our 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 our 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 our capital expenditure plans may result in a delay in development or production on our properties.

Reserve Estimates

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

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;

- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

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

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

In accordance with applicable securities laws, our 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 our 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 we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in our reserves since that date.

Management of Growth

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

Dividends

The amount of future cash dividends we pay, 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, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond our control, our dividend policy 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 us 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 us 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, our ability 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 we are required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Reliance on Key Personnel

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

Operational Dependence

Other companies operate some of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside our 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.

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 our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our 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 our cost 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 we are ultimately able to produce from our 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 us to incur costs to remedy such discharge. Although we believe that we 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 our business, financial condition, results of operations and prospects.

Liability Management

Alberta and Saskatchewan 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 our 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. See: "*Industry Conditions*".

Issuance of Debt

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

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. Our actual interest in our properties may accordingly vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect our title to the oil and natural gas properties we control that could impair our activities on such properties and result in a reduction of the revenue we receive therefrom.

Expiration of Licences and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we or the holder of the licence or lease fail 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 our licences or leases or the working interests relating to a licence or lease may have a material adverse effect on our business, financial condition, results of operations and prospects.

Income Taxes

We file all required income tax returns and believe that we are in full compliance with the provisions of the *Income Tax Act* (Canada) 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, 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 us. Furthermore, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider 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 our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with our business and operations. 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 we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, may realize less than their carrying value on our financial statements.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future 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 OPEC and the ongoing global credit and liquidity concerns. This volatility may in the future affect our ability to obtain equity or debt financing on acceptable terms.

Competition

The petroleum industry is competitive in all of its phases. We compete 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. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our current properties, but also on the ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/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 our production revenues. Accordingly, Canadian/United States exchange rates could affect the future value of the our reserves as determined by independent evaluators.

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

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

Litigation

In the normal course of our operations, we 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 us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although we maintain 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, we 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 our available funds. The occurrence of a significant event for which we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Breach of Confidentiality

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

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 our goods.

Third Party Credit Risk

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

Conflicts of Interest

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

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 and may delay exploration and development activities.

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 we do. There can be no assurance that we 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 we currently use or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be affected adversely and materially. If we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could also be materially adversely affected.

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. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us to comply with greenhouse gas 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* and a participant to the Copenhagen Agreement (a non-binding agreement created by the *United Nations Framework Convention on Climate Change*), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. These greenhouse gas emission reduction targets are not binding, however. Some of our facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage greenhouse gas emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our 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 us or our operations and financial condition.

Dilution

We may make future acquisitions or enter into financings or other transactions involving the issuance of Common Shares which may be dilutive.

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 we acquire or discover. 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 our net production revenue.

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. We are not aware that any claims have been made in respect of our properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on our business, financial condition, results of operations and prospects.

Expansion into New Activities

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

Forward-Looking Information May Prove Inaccurate

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any: (a) director or executive officer; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of our voting securities; and (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction since our inception in 2011 that has materially affected or is reasonably expected to materially affect us.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are KPMG LLP, Chartered Accountants, Suite 3100, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9. KPMG LLP has been our auditors since inception.

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts that we have entered into prior to the date of this Annual Information Form, which can reasonably be regarded as presently material, are the following:

1. the Credit Facility;

2. the Stock Option Plan; and

3. the Restricted Share Award Plan.

Copies of these contracts may be viewed at the website maintained by the Canadian Securities Administrators at www.sedar.com.

EXPERTS

Interests of Experts

To our knowledge, no registered or beneficial interests, direct or indirect, in any of our securities or other property: (i) were held by Sproule or by the "designated professionals" (as defined in Form 51-102F2) of Sproule, when Sproule prepared the Sproule Report; (ii) were received by Sproule or the designated professionals of Sproule after Sproule prepared the Sproule Report; or (iii) is to be received by Sproule or the designated professionals of Sproule.

KPMG LLP are our auditors and have confirmed that they are independent with respect to us within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our SEDAR profile at www.sedar.com and on our website at www.wcap.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our proxy materials relating to our annual and special shareholders meeting to be held on June 5, 2014. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2013 and the related management's discussion and analysis.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

Cardinal Energy Ltd.
1400, 440 - 2 Avenue SW
Calgary AB T2P 5E9
Tel: (403) 234.8681
Fax: (403) 234-0603

APPENDIX A

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

Management of Cardinal Energy Ltd. ("**Cardinal**") is responsible for the preparation and disclosure of information with respect to Cardinal's oil and natural 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 Cardinal's reserves data. The report of the independent qualified reserves evaluator is presented below.

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

(a) reviewed Cardinal'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 has reviewed Cardinal's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

(d) the content and filing with securities regulatory authorities of Form 51-101F2 containing reserves data and other oil and gas information;

(e) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(f) 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) "*M. Scott Ratushny*"
M. Scott Ratushny
Chief Executive Officer

(signed) "*David D. Johnson*"
David D. Johnson
Director, Chairman of the Reserves Committee and Member of the Audit Committee and the Governance and Compensation Committee

(signed) "*Shane Peet*"
Shane Peet
Chief Operating Officer

(signed) "*James C. Smith*"
James C. Smith
Director and Member of the Audit Committee and the Reserves Committee

March 27, 2014

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR FORM 51-101F2

To the board of directors of Cardinal Energy Ltd. (the "**Company**"):

1. We have evaluated the Company'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 Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $000s)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Evaluation of the P&NG Reserves of Cardinal Energy Ltd. As of December 31, 2013, prepared December 2013 to March 2014	Canada	-	395,278	-	395,278

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 for events and circumstances occurring after their respective preparation dates.

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

Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, March 21, 2014.

"Originally Signed by Khani Ghaffari, P.Eng"
Khani Ghaffari, P.Eng
Senior Petroleum Engineer and Associate

" Originally Signed by Doug McNichol, P.Eng"
Doug McNichol, P.Eng
Senior Petroleum Engineer and Associate

"Originally Signed by Alex Kovaltchouk, P.Geo. on behalf of George Strother-Steward, P.Geol"
George Strother-Stewart, P.Geol
Senior Petroleum Geologist and Partner

"Originally Signed by Nora T. Stewart, P.Eng"
Nora T. Stewart, P.Eng
Vice President, Canada and Partner

APPENDIX C

CARDINAL ENERGY LTD.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

Establishment of Committee

The board of directors (the "**Board**") of Cardinal Energy Ltd. ("**Cardinal**" or the "**Corporation**") hereby establishes a committee of the Board to be called the Audit Committee (the "**Committee**").

Role and Objective

1. The purpose of the Committee is to assist the Board in fulfilling its responsibilities for the oversight of the following respecting Cardinal:

   (a) the nature and scope of the annual audit;

   (b) the oversight of management's reporting and practices on internal financial and accounting standards;

   (c) the review of the adequacy of financial information, accounting systems and procedures;

   (d) financial reporting and financial statements,

   and the Board has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements, management's discussion and analysis and any public disclosures containing financial information.

2. The primary objectives of the Committee are as follows:

   (a) to assist directors of the Corporation ("**Directors**") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Cardinal and related matters;

   (b) to provide better communication between the Directors and external auditors;

   (c) to enhance the external auditor's independence;

   (d) to increase the credibility and objectivity of financial reports; and

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

Membership of Committee

1. The Committee shall be comprised of at least three (3) Directors or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument52-110 – *Audit Committees* (as amended from time to time) ("**MI 52-110**") unless the Board determines that the exemption contained in MI 52-110 is available and determines to rely thereon.

2. The Board may from time to time designate one of the members of the Committee to be the Chairman of the Committee (the "**Chairman**").

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

Specific Duties and Responsibilities

To carry out its responsibilities, the Committee shall:

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

2. approve the compensation of the external auditors;

3. satisfy itself on behalf of the Board with respect to Cardinal's internal control systems;

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

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

    (b) reviewing any alternative financial or accounting disclosure which have been considered and the reasons for the treatment selected;

    (c) reviewing significant accruals, reserves or other estimates such as the goodwill impairment assessment;

    (d) reviewing the scope and quality of the audit;

    (e) reviewing accounting treatment of unusual or non-recurring transactions;

    (f) reviewing the adequacy of the Corporation's accounting personnel;

    (g) ascertaining compliance with covenants under loan agreements;

    (h) reviewing all significant or unusual transactions outside the normal course of business of Cardinal;

    (i) reviewing disclosure requirements for commitments and contingencies;

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

    (k) reviewing litigation, claims or contingencies or any tax assessments considered material or potentially material;

    (l) reviewing unresolved differences or disagreements between management of the Corporation ("**Management**") and the external auditors;

    (m) obtain explanations of significant variances with comparative reporting periods; and

    (n) meeting in camera with management and separately with the external auditors;

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

6. with respect to the appointment of external auditors by the Board:

   (a) recommend to the Board the external auditors to be nominated;

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

   (c) on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with Cardinal to determine the auditors' independence;

   (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, if required; and

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

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

8. establish a procedure for:

   (a) the receipt, retention and treatment of complaints received by Cardinal regarding accounting, internal accounting controls or auditing matters; and

   (b) the confidential, anonymous submission by employees of Cardinal of concerns regarding questionable accounting or auditing matters; and

9. review and approve Cardinal's and its subsidiary's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Cardinal.

Meetings and Administrative Matters

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

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

3. A quorum for meetings of the Committee will be a majority of its members. No business may be transacted by the Committee except at a meeting of its members at which a quorum of the Committee is present or by a resolution in writing signed by all the members of the Committee. Meetings may occur via telephone or teleconference.

4. The time at which and place where the meetings of the Committee shall be held and the calling of meetings and the procedure in all respects at such meetings shall be determined by the Committee, unless otherwise determined by the by-laws of the Corporation or by resolution of the Board.

5. Meetings of the Committee should be scheduled to take place at least four times per year and at such other times as the Chairman may determine. The Chief Financial Officer of Cardinal will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

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

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

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

9. Minutes of the Committee will be recorded and maintained.

10. If determined appropriate, following meetings of the Audit Committee, a list of tasks or matters to be followed up upon shall be prepared including the time table for completion thereof and the responsibility for completion, the status of which matter shall be reviewed at the next meeting of the Committee or as otherwise determined by the Committee.

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

12. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a Director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee each member will hold such office until the Committee is reconstituted.

13. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chairman of the Board by the Chairman.

Approved by the Board of Directors on August 27, 2012.