ANNUAL INFORMATION FORM

for the year ended December 31, 2013

March 21, 2014

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ABBREVIATIONS

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	one barrel	Mcf	one thousand cubic feet
bbl	barrels	MMcf	one million cubic feet
bbl/d	barrels per day	Bcf	one billion cubic feet
Mbbl	thousand barrels		
BOE	barrels of oil equivalent of natural gas on the basis of 1 BOE for 6 Mcf of natural gas (unless otherwise indicated)	Mcf/d	one thousand cubic feet per day
MBOE	one thousand barrels of oil equivalent	MMcf/d	one million cubic feet per day
MMBOE	one million barrels of oil equivalent	GJ	gigajoule
BOE/d	barrels of oil equivalent per day	GJs/d	gigajoules per day
NGL	natural gas liquids	Btu	British thermal unit
stb	standard stock tank barrel	MMbtu	million British thermal units

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf to one 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. This conversion factor is an industry accepted norm and is not based on either energy content or current prices. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf:1 bbl, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indication of value.

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
m^3	cubic metres
$000's	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	thousand cubic metres ("10^3m^3")	0.0282
thousand cubic metres	Mcf	35.494
bbl	cubic metres ("m^3")	0.159
cubic metres	bbl	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

"**BMEC**" means Black Mountain Energy Corporation, a corporation incorporated under the laws of Alberta which was amalgamated with Old Gear on May 1, 2010;

"**BMEC Acquisition**" means the offer of BMEC to purchase all of the issued and outstanding Class A common shares of Old Gear from the shareholders of Old Gear in exchange for 1.4 common shares of BMEC and 0.258125 non-voting preferred shares of BMEC for each Class A common share of Old Gear outstanding;

"**Board**" means the board of directors of the Corporation;

"**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;

"**Common Shares**" means common shares in the capital of Gear;

"**Corporation**" or "**Gear**" means Gear Energy Ltd., a corporation amalgamated under the laws of the Province of Alberta;

"**EOR**" means enhanced oil recovery;

"**Gear Credit Facilities**" means the $75 million credit facility with a syndicate of banks entered into by Gear on April 25, 2013;

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent oil and natural gas reservoir engineers of Calgary, Alberta;

"**GLJ Report**" means the independent engineering evaluation of Gear's oil, natural gas liquids and natural gas interests prepared by GLJ effective December 31, 2013 and dated February 28, 2014;

"**Gross**" means:

(a) in relation to an entity's interest in production and reserves, its "company gross reserves", which are such entity's working interest (operating and non-operating) before deduction of royalties and without including any royalty interest of such entity;

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

(c) in relation to properties, the total area of properties in which an entity has an interest;

"**Lift**" means Lift Resources Inc., a corporation incorporated under the laws of Alberta which was amalgamated with Gear on September 21, 2011;

"**Net**" means:

(d) in relation to an entity's interest in production and reserves, such entity's interest (operating and non-operating) after deduction of royalties obligations, plus the entity's royalty interest in production or reserves;

(e) in relation to wells, the number of wells obtained by aggregating an entity's working interest in each of its gross wells; and

(f) in relation to the Corporation's interest in a property, the total area in which an entity has an interest multiplied by the working interest owned by it;

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* adopted by the Canadian Securities Administrators;

"**Old Gear**" means Gear Energy Ltd., a corporation incorporated under the laws of Alberta which was amalgamated with BMEC on May 1, 2010;

"**Options**" means options to purchase Common Shares granted under the Option Plan;

"**Option Plan**" means the share option plan of the Corporation;

"**Preferred Shares**" means preferred shares, issuable in series, in the capital of Gear;

"**Series 1 Preferred Shares**" means the authorized Series 1 preferred shares in the capital of Gear;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5^{th} Supp.), as amended, including the regulations;

"**TSX**" means the Toronto Stock Exchange;

"**WCS**" means Western Canadian Select; and

"**WTI**" means West Texas Intermediate.

CONVENTIONS

Certain terms used herein are defined under the heading "Glossary of Terms".

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2013.

READER ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, the financial and business prospects and financial outlook, reserve and production estimates, drilling and re-completion plans, timing of drilling, re-completion and tie-in of wells, productive capacity of wells and productive capacity of wells and capital expenditures and the timing thereof, the timing and completion of the Offering (as defined herein), the exercise of the Over-Allotment (as defined herein), the proceeds to be received by the Corporation from the Offering, the effect of government announcements, proposals and legislation, plans regarding hedging, expected or anticipated production rates, timing of expected production increases, weighting of production between different commodities, expected commodity prices, price differentials, exchange rates, production expenses, transportations costs and other costs and expenses, maintenance of productive capacity and capital expenditures and methods of financing thereof, may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of the Corporation's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Corporation believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Corporation can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this Annual Information Form, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Corporation operates; the timely receipt of any required regulatory approvals; the ability of the Corporation to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Corporation has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Corporation to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; and the ability of the Corporation to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

CORPORATE STRUCTURE

Name, Address and Incorporation

Gear is an Alberta-based growth-oriented, junior oil and gas company engaged in the exploration for, and the acquisition, development and production of, oil and natural gas reserves in the Western Canadian Sedimentary Basin, with a focus on heavy oil.

Gear was incorporated on June 25, 2007 under the ABCA as "Black Mountain Energy Corporation". On January 29, 2010, BMEC acquired all of the issued and outstanding common shares of Old Gear pursuant to the BMEC Acquisition. BMEC and Old Gear amalgamated on May 1, 2010 and continued under the name "Gear Energy Ltd."

On June 3, 2010, Gear amended its articles to: (i) consolidate the Common Shares on the basis of one post-consolidation Common Share for every five pre-consolidation Common Shares; and (ii) to convert the then-issued and outstanding Series 1 Preferred Shares to Common Shares on the basis of one post-consolidation Common Share for every five pre-consolidation Series 1 Preferred Shares.

Gear was amalgamated under the provisions of the ABCA on September 21, 2011 with its wholly-owned subsidiary, Lift and continued under the name "Gear Energy Ltd."

The head office of Gear is located at Suite 2600, 500 – 4th Avenue S.W., Calgary, Alberta T2P 2V6 and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Unless otherwise stated, disclosure in this Annual Information Form of the share capital of Gear is presented after giving effect to the foregoing amendments to the Articles of Gear.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

The following is a summary of the significant events in the development of the Corporation's business over the last three completed financial years.

Year Ended December 31, 2011

Drilling operations commenced in early 2011 with 3 gross (3 net) vertical heavy oil wells drilled in the Vermilion Sparky pool. Drilling within the Wildmere Lloydminster pool commenced after break-up in May. Gear drilled and brought on stream 25 horizontal heavy oil wells at Wildmere in the second half of the year and continued to invest in both inventory expansion and cost reduction projects.

Pursuant to a plan of arrangement under the ABCA under an arrangement agreement entered into between Gear and Lift dated effective August 26, 2011, as amended and restated, on September 21, 2011, Gear acquired all of the existing and outstanding common shares of Lift, an Alberta private company focused on heavy oil in close proximity to Gear's Wildmere area. The total consideration for the transaction was $23 million, which consisted of approximately 2.63 million Common Shares (with an equal number of share rights attached) and cash of approximately $13.1 million offset by the acquisition of $1.9 million of positive working capital. An additional aggregate of approximately 158,000 Common Shares were issued to former Lift shareholders in the 10 months following closing of the acquisition of Lift upon the automatic exercise of the share rights issued as a part of the transaction. Immediately following the acquisition of Lift, the Corporation and Lift amalgamated and continued under the name "Gear Energy Ltd." Concurrent with the close of the acquisition, Gear's credit facility was expanded from $40 million to $50 million.

In addition to drilling operations, in 2011 Gear continued to invest in the Wildmere EOR project. Lab work on the cores taken in 2010 and a field simulation were performed with encouraging results at each major juncture throughout the year. By the end of 2011, Gear was confident enough in the preliminary work that it sanctioned a pilot for a polymer injection project and began the process of gaining government approvals.

During the second half of the year, Gear initiated a risk management program and began to actively look at hedging contracts as a way to protect the rates of return on our capital program.

Throughout 2011, Gear invested a total of $58.4 million of capital with $28 million dedicated to drilling and completions, $9 million spent on production equipment and facilities, $20 million on net acquisitions and $1 million on land, seismic and other expenses.

Year Ended December 31, 2012

Gear's drilling program in 2012 again focused on horizontal heavy oil wells. Gear drilled 35 gross (33 net) wells with a 97 per cent success rate. In addition to operations spending, Gear invested $5 million to acquire undeveloped acreage at Crown sales and a further $4 million to acquire assets predominantly located in Maidstone, Saskatchewan. Through organic drilling only, Gear was able to increase its company interest average annual production 51 per cent from 2,299 boe/d in 2011 to 3,476 boe/d in 2012.

Throughout the year, Gear divested of certain British Columbia gas properties for proceeds of $2.7 million. In addition, Gear shut-in three non-economic gas pools. Gear continued to realize the benefits of investing in cost reduction projects with operating costs being reduced each quarter of the year. Along with a focus to be a low cost heavy oil operator and to maximize cash flow, Gear began to physically hedge heavy oil production by selling its heavy oil to buyers who ship by rail to refiners in the Gulf Coast of the United States as widening WCS differentials were expected, particularly in the fourth quarter. Gear reached a high of 33 per cent of daily oil volumes shipped by rail in the fourth quarter of 2012.

Gear continued to advance the Wildmere Lloydminster EOR pilot project with further testing and simulation work and by September 15, 2012 the pilot facility was constructed and injection of polymer had commenced.

Total capital spending in 2012, including net acquisitions, was $47 million, including $28 million invested in drilling and completions, $11 million invested in production equipment and facilities, $2 million invested in net acquisitions, and $6 million invested in land, seismic and other expenses. The success of the capital program increased the Corporation's estimate of potential heavy oil drilling inventory to 230 locations by year end 2012.

In May 2012, Gear increased its credit facility from $50 million to $55 million. In September 2012, Gear further increased its credit facility from $55 million to $60 million.

Year Ended December 31, 2013

During the second quarter of 2013, the Gear Credit Facilities, which replaced Gear's previous credit facility, were entered into for total available funds of $75 million.

Total capital spending in 2013, including net acquisitions, was $53 million. The majority of these funds were spent to drill 47 gross (42 net) wells with a 98 per cent success rate. The 2013 drilling program focussed on further development of the Wildmere area as well a de-risking the Company’s two new core areas, Maidstone Cummings and Wildmere Cummings. In addition to the 2013 drilling program Gear increased heavy oil amendable land holdings by purchasing 2,600 hectares of new prospective lands in Alberta and Saskatchewan.

During 2013, a number of changes to the membership of the Board occurred, including the appointments of Messrs. Raymond Cej and Greg Bay on January 22, 2013 and March 25, 2013, respectively, and the resignations of Messrs. Scott Inglis and Richard Braund on March 25, 2013 and August 12, 2013, respectively.

On November 13, 2013, the Corporation filed a non offering final prospectus and became a reporting issuer in the Provinces of Alberta and Ontario. On November 18, 2013, the Common Shares began trading on the TSX under the symbol "GXE".

Gear's current approved capital budget for 2014 is $70 million, $46 million allocated for development drilling and recompletions, $5 million for EOR commercialization, $14 million for land, seismic and exploration and $5 million for facilities, maintenance and abandonments.

Recent Developments

On March 6, 2014, the Corporation entered into an agreement relating to the sale of 12,500,000 Common Shares on a bought deal basis to a syndicate of underwriters co-led by FirstEnergy Capital Corp. and Peters & Co. Limited and including RBC Dominion Securities Inc., GMP Securities L.P., Haywood Securities Inc. and AltaCorp Capital Inc. (collectively, the "**Underwriters**") at a price of $4.00 per Common Share for gross proceeds of $50 million (the "**Offering**"). Following the announcement of the Offering, the Corporation and the Underwriters agreed to increase the number of Common Shares to be sold under the Offering from 12,500,000 Common Shares to 14,000,000 Common Shares (the "**Offering Increase**").

The Corporation also granted the Underwriters an option (the "**Over-Allotment Option**") which may be exercised in whole or in part up to 30 days after the closing of the Offering, to purchase up to 1,875,000 additional Common Shares at a price of $4.00 per Common Share to cover over-allotments and for market stabilization purposes. Pursuant to the Offering Increase and assuming the Over-Allotment Option is exercised in full, the Corporation will realize gross proceeds of $63,500,000. The Offering is anticipated to close on or about March 28, 2014 and is subject to the customary conditions including receipt of all necessary regulatory and stock exchange approvals.

Significant Acquisitions

The Corporation did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations.*

DESCRIPTION OF THE BUSINESS

General

Gear is a Calgary, Alberta based junior Canadian crude oil and natural gas exploration and production company with a focus on heavy oil. All of the Corporation's oil and gas properties are located in Alberta, British Columbia and Saskatchewan. The Corporation currently has core holdings in east central Alberta and west central Saskatchewan. The Corporation has a significant land position in Alberta, British Columbia and Saskatchewan and intends to continue to evaluate additional oil and gas assets in Alberta, British Columbia and Saskatchewan.

Business Plan and Corporate Strategy

Gear's strategy is to provide long term production and cashflow growth on a per debt adjusted share basis as a low cost heavy oil operator. The Corporation's business plan contemplates that the Corporation will pursue exploration, development and exploitation drilling, complimented with property or corporate acquisitions exhibiting synergies in land, facilities, production and operating efficiencies.

Gear plans to achieve this growth by pursuing assets with the following characteristics:

- Geographically focused
- Definable resource base with low risk production
- Repeatable projects that are statistically economic
- Multiple producing horizons
- Easy surface access and existing infrastructure
- High operatorship percentage
- Control of timing and costs of projects

See "*Risk Factors*".

Gear's strategy to attempt to enhance returns on its assets is by:

- Drilling and developing on controlled lands
- Focusing on operational and cost efficiencies
- Continually improving operations through innovation and imitation
- Adopting and refining advanced drilling and completing techniques
- Pursuing strategic acquisitions with significant potential synergies

In reviewing potential drilling or acquisition opportunities, Gear gives consideration to a variety of criteria, including: (i) the capital required to secure or evaluate the investment opportunity; (ii) if successful, the potential return on the project; (iii) the likelihood of success; (iv) the risk of return versus cost of capital; (v) the strategic benefits to Gear; and (vi) Gear's ability to operate a project.

The Board may, in its discretion, approve asset or corporate acquisitions or investments, including those acquisition or investments that do not conform to the guidelines discussed above based upon the Board's consideration of, among other things, the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

The Board has approved a $70 million capital expenditure budget for 2014. The budget targets expenditures balanced between low risk, high rate of return development drilling and advancement of efforts to expand and de-risk other potential new core heavy oil assets. With current price forecasts, the budget is estimated to provide value creation including both production and cash flow growth on a per debt adjusted share basis and will be funded through a combination of cash flow, equity financing and debt. Approximately 66 per cent of capital will target production growth from primarily horizontal oil drilling. An additional 20 per cent of the budget is directed towards inventory expansion through a combination of land acquisitions, seismic, and drilling of several new plays. The remaining capital will support continued investment in enhanced oil recovery, recompletions, gas gathering systems, and a variety of field based operating cost improvement projects.

The budget includes an anticipated material improvement in the cash flow generating capabilities of Gear through a combination of a higher liquid weighting, lower royalties, lower operating costs and lower interest and general and administrative costs per boe. Gear plans to drill 59 gross (55 net) oil locations during the year which will assist in increasing the production liquid weighting from 93 per cent to approximately 98 per cent. Corporate royalties are expected to decrease from 23 per cent in 2013 to approximately 18 per cent - 20 per cent in 2014, as a result of increased production weighting on crown lands offering low initial royalties and horizontal drilling incentives. The budgeted operating costs are predicted to decline slightly and range between $17.00 to $18.00 per boe.

The amount of capital the Corporation will expend for its 2014 exploration and development program and the nature of its expenditures may vary materially based on commodity prices, other industry conditions and the Corporation's drilling results as the year progresses. Access to additional capital may spur an expansion of the program; however, a reduction in the Gear Credit Facilities may lead to a reduction in the 2014 program. See "*Risk Factors*" for further details.

If the Corporation is unable to complete its proposed 2014 capital exploration and development program in 2014 as proposed, the balance of the program may be deferred to 2015 or beyond and the Corporation's anticipated growth in its future production, cash flows and reserves would then be delayed.

Specialized Skill and Knowledge

Gear believes that its team has all of the key components to successfully implement its business plan: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; extensive experience in oil and gas exploration and development in Western Canada; and an entrepreneurial spirit that allows Gear to effectively identify, evaluate and execute on value-added initiatives. See "*Directors and Executive Officers*".

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Companies operating in the upstream petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration and development, commodity prices, foreign exchange rates, interest rates and environmental damages. See "*Risk Factors —Competition*".

Gear expects the intense level of competition to continue in the future. Gear competes with a substantial number of other entities, certain of which have greater technical or financial resources particularly when it comes to acquiring reserves, oil and gas mineral rights, skilled industry personnel, access to end user markets, and capital to finance their activities. With the maturing nature of the Western Canadian Sedimentary Basin, access to new prospects is becoming more competitive and complex and Gear's ability to execute its business plan of growing oil and gas reserves and cash flow will depend not only on its ability to exploit and develop existing properties but also its ability to identify and acquire additional properties or prospects for exploratory and development drilling. Gear believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

Cyclical Nature of Business

In general, the energy business is cyclical in nature and heavily dependent on macro-economic cycles. In periods of economic expansion and growth the demand for energy increases as economies build inventory and productive capacity. Generally speaking in periods of economic contraction or recession, demand for energy declines. These macroeconomic cycles often impact global, North American and local prices for commodities, particularly oil and gas prices.

Demand for heavy oil begins to increase in the spring time and peaks in the summer months as heavy oil is often the base feed stocks which supply refineries, which make end products such as transportation fuels, heating oils, and asphalt for road paving. During the fall, refiners switch from making gasoline for summer driving season and asphalt for paving season and enter turn around season creating temporary lower demand for heavy crudes while these refineries undergo maintenance and repairs. Demand picks up again with a focus on making heating fuels until the spring comes and refiners again switch to focus on building gasoline stocks for the summer season.

Generally, Gear's operations are not cyclical. With the exception of a few months in the spring when conditions are wet and road damage can occur with heavy traffic, often referred to as "break up", Gear's operating areas are accessible year round. Gear invests capital and has ongoing operations year round with lower levels of activity during "break up". To the extent that a "break up" period is longer than normal, such as in the second quarter of 2013 when conditions in the Western Canadian Sedimentary Basin were extremely wet, it can have an impact on Gear's ability to execute its capital expenditure program. See "*Risk Factors – Seasonality*".

Environmental Protection

All phases of the oil and natural gas industry are subject to a variety of federal and provincial legislation. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions or various substances produced in association with oil and natural gas. Compliance with such legislation may require significant expenditures and a breach may result in fines and penalties some of which may be material. Environmental legislation is constantly evolving and is expected to result in stricter standards and enforcement, larger fines and liabilities and potentially increased capital and operating costs. No assurances can be given that environmental laws will not result in a curtailment of production or a material increase in cost adversely affecting the Corporation's financial condition.

For a description of the financial and operational effects of environmental protection requirements on the capital expenditures, earnings and competitive position of Gear see "*Industry Conditions — Environmental Regulation*" and "*Risk Factors — Environmental*".

Employees

As at December 31, 2013, Gear had 18 full time employees and three consultants located at its Calgary office, and 4 full time employees and a number of contract operators in various field locations.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated February 28, 2014. The effective date of the Statement is December 31, 2013 and the preparation date of the Statement is February 13, 2014.

Disclosure of Reserves Data

The Corporation engaged GLJ to provide an evaluation of the Corporation's proved and proved plus probable reserves as at December 31, 2013. The reserves data set forth below (the "**Reserves Data**") is based upon the GLJ Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas proved and probable reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The GLJ Report has been prepared in accordance with the standards and the reserve definitions contained in the COGE Handbook and NI 51-101. The Reserves Committee of the Board has reviewed and approved the GLJ Report and this statement. The Report of Management and

Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Schedules "A" and "B" hereto, respectively.

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

All evaluations of future net production revenue set forth in the tables below are based on forecast prices and costs and are after direct lifting costs and future capital investments. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF CORPORATION OIL AND 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		TOTAL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (MBOE)	Net (MBOE)
Proved Developed										
Producing	-	1.9	5,375	4,474	1,579	1,482	10	8	5,649	4,731
Non-Producing	-	-	19	16	1,403	1,277	1	1	254	230
Proved										
Undeveloped	-	-	2,288	2,000	4,140	3,770	60	43	3,037	2,672
Total Proved	-	1.9	7,682	6,490	7,122	6,529	71	53	8,941	7,633
Probable	-	1.4	5,160	4,403	8,359	7,262	161	124	6,715	5,739
Total Proved plus Probable	-	3.2	12,843	10,894	15,481	13,791	233	176	15,655	13,372

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/BOE)
Proved Developed											
Producing	186.0	163.2	145.5	131.5	120.2	186.0	163.2	145.5	131.5	120.2	30.74
Non-Producing	1.8	1.5	1.2	1.1	0.9	1.8	1.5	1.2	1.1	0.9	5.43
Proved Undeveloped	58.7	45.1	35.0	27.5	21.7	47.3	35.6	27.0	20.6	15.7	13.11
Total Proved	246.4	209.7	181.7	160.0	142.8	235.1	200.2	173.7	153.1	136.8	23.81
Probable	173.1	123.9	92.3	71.0	56.0	134.0	93.5	68.0	51.0	39.1	16.09
Total Proved plus Probable	419.6	333.6	274.0	231.0	198.8	369.1	293.7	241.6	204.0	175.9	20.49

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

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	WELL ABANDONMENT COSTS (MM$)	FUTURE NET REVENUE BEFORE INCOME TAXES (MM$)	INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER INCOME TAXES (MM$)
Total Proved	607.0	96.7	203.7	54.6	5.6	246.4	11.3	235.1
Total Proved plus Probable	1,067.7	167.3	361.7	111.5	7.6	419.6	50.5	369.1

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) (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/Boe) ($/Mcfe)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	152	70.43/Boe
	Heavy Oil (including solution gas and other by-products)	176,494	27.11/Boe
	Natural Gas (including by-products but excluding solution gas from oil wells)	5,086	0.76/Mcfe
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	242	64.83/Boe
	Heavy Oil (including solution gas and other by-products)	265,194	24.29/Boe
	Natural Gas (including by-products but excluding solution gas from oil wells)	8,605	0.59/Mcfe

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the GLJ Report are based on the definitions and Guidelines contained in the COGE Handbook. A summary of those definitions is set forth in the "*Glossary*".

3. Levels of Certainty for Reported Reserves:

   The qualitative certainty levels referred to in the reserves definitions contained in the "*Glossary*" 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 reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

   (a) at least a 90 per cent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

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

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

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

4. Forecast Costs and Price Assumptions

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

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL							
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Oil Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Natural Gas AB Plant Gate Spot Gas Price ($Cdn/Mcf)	Pentanes Plus Edmonton ($Cdn/bbl)	Butanes Price Edmonton ($Cdn/bbl)	Inflation Rates(1) %/Year	Exchange Rate(2) ($US/$Cdn)
Forecast								
2014	97.50	92.76	65.72	3.81	105.20	73.22	2.0	0.95
2015	97.50	97.37	70.03	4.04	107.11	75.95	2.0	0.95
2016	97.50	100.00	72.85	4.28	107.00	78.00	2.0	0.95
2017	97.50	100.00	72.85	4.51	107.00	78.00	2.0	0.95
2018	97.50	100.00	72.85	4.75	107.00	78.00	2.0	0.95
2019	97.50	100.00	72.85	4.98	107.00	78.00	2.0	0.95
2020	98.54	100.77	73.42	5.11	107.82	78.60	2.0	0.95
2021	100.51	102.78	74.90	5.21	109.97	80.17	2.0	0.95
2022	102.52	104.83	76.42	5.32	112.17	81.77	2.0	0.95
2023	104.57	106.93	77.97	5.42	114.41	83.40	2.0	0.95
2024+	Escalated oil, gas and product prices at 2% per year thereafter							

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized, before transportation and financial derivative contracts, by the Corporation for the year ended December 31, 2013, were $3.11/Mcf for natural gas, $86.87/bbl for light crude oil, $69.12/bbl for heavy oil and $48.84/bbl for NGLs.

5. Well abandonment costs have only been included for wells with reserves assigned. Additional abandonment costs associated with existing wells and lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

6. The forecast price and cost assumptions assume the continuance of current laws and regulations.

7. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

8. The after-tax net present value of the Corporation's properties here reflects the tax burden on the properties on a stand-alone basis and utilizing the Corporation's tax pools. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.

Reconciliations of Changes in Gross Reserves

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2012	-	-	-	5,903	4,598	10,502
Discoveries	-	-	-	61	15	76
Extensions	-	-	-	2,475	543	3,018
Infill Drilling	-	-	-	443	224	666
Improved Recovery	-	-	-	145	79	223
Technical Revisions	-	-	-	45	(295)	(251)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	(13)	(3)	(16)
Production	-	-	-	(1,376)	-	(1,376)
December 31, 2013	-	-	-	7,682	5,160	12,843

FACTORS	NATURAL GAS LIQUIDS Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	NATURAL GAS Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	TOTAL Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
December 31, 2012	70	162	232	7,779	8,430	16,210	7,270	6,165	13,435
Discoveries	-	-	-	-	-	-	61	15	76
Extensions	-	-	-	-	-	-	2,475	543	3,018
Infill Drilling	-	-	-	-	-	-	443	224	666
Improved Recovery	-	-	-	-	-	-	145	79	223
Technical Revisions	6	(1)	5	70	(78)	(7)	62	(309)	(247)
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(1)	1	-	(88)	6	(82)	(29)	(1)	(30)
Production	(4)	-	(4)	(640)	-	(640)	(1486)	-	(1486)
December 31, 2013	71	162	233	7,122	8,359	15,481	8,941	6,715	15,655

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the remaining proved undeveloped reserves and the remaining probable undeveloped reserves, each by product type, attributed to Gear's assets for the years ended December 31, 2013, 2012 and 2011 and in the aggregate before that time.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl) First Attributed	Light and Medium Oil (Mbbl) Cumulative at Year End	Heavy Oil (Mbbl) First Attributed	Heavy Oil (Mbbl) Cumulative at Year End	Natural Gas (MMcf) First Attributed	Natural Gas (MMcf) Cumulative at Year End	NGLs (Mbbl) First Attributed	NGLs (Mbbl) Cumulative at Year End	Oil Equivalent (Mboe) First Attributed	Oil Equivalent (Mboe) Cumulative at Year End
Prior thereto	-	-	760	760	4,446	4,446	60	60	1,561	1,561
2011	-	-	1,168	1,368	-	4,185	-	60	1,168	2,126
2012	-	-	1,217	1,408	39	4,191	-	60	1,223	2,166
2013	-	-	1,356	2,288	-	4,140	-	60	1,356	3,037

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)		Oil Equivalent (MBoe)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	132	132	707	707	5,851	5,851	77	77	1,891	1,891
2011	-	-	1,200	1,330	2,160	7,425	84	160	1,644	2,728
2012	-	-	2,858	3,224	13	7,305	-	158	2,860	4,600
2013	-	-	1,588	3,337	-	7,290	-	158	1,588	4,710

Note:

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

In general, once proved and/or probable reserves are identified, they are included in Gear's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within two to three years; however these locations will continue to be re-evaluated to assess their relative economic merits when compared to other projects available to the Corporation. A number of factors that could result in delayed or cancelled development are as follows:

- development of a superior opportunity inventory to select from;
- changing economic conditions (due to pricing, royalties, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

See "*Other Oil and Gas Information – Principal Properties*", "*Other Oil and Gas Information – Future Development Costs*" and "*Other Oil and Gas Information - Capital Expenditures*" for a description of the Corporation's exploration and development plans and expenditures.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability and pricing of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any unusually high development costs or operating costs to produce and sell any material portion of its reserves. Where required, capital to construct facilities and pipelines necessary to deliver the forecasted products to market has been deducted from the estimates of cash flows used to calculate future net revenue. The Corporation has not entered into any contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations described under the heading "*Other Oil and Gas Information – Forward Contracts and Marketing*".

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below:

	Forecast Capital Costs (M$)	
Year	Proved Reserves	Proved Plus Probable Reserves
2014	39,761	48,556
2015	14,245	54,085
2016	156	8,313
2017	13	13
2018	-	-
Thereafter	393	579
Total Undiscounted	54,567	111,546

On an ongoing basis, Gear will use internally generated cash flow from operations, debt and new equity issues if available on favourable terms to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for the Corporation.

Other Oil and Gas Information

Principal Properties

The Corporation is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. All of the Corporation's current operations are in the provinces of Alberta and Saskatchewan, with some minor operations in British Columbia.

The following is a description of the Corporation's oil and natural gas properties as at the date hereof, unless otherwise stated. The reserve amounts stated are gross reserves, as at December 31, 2013 based on forecast costs and prices as evaluated in the GLJ Report (see "*Reserves Data*"). The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. The production values are all stated on a company interest basis.

Wildmere Area, Alberta

The Wildmere field is located within Townships 47, 48 and 49, and Ranges 3, 4, 5 and 6 W4, is approximately 200 kilometres southeast of Edmonton, Alberta and is Gear's largest producing property. The property consists of approximately 21,575 gross (20,050 net) acres of lands with no material expiries as the majority of the lands have been continued pursuant to the applicable tenure regulations.

The Wildmere area is a heavy oil area characterized by unconsolidated Upper Mannville group clastic reservoirs with depths ranging from 600 meters to 700 meters. While the Lloydminster formation has been the most exploited interval, the Colony, Cummings and Sparky formations have all proven to be successful development targets for heavy oil on Gear acreage.

Each of Gear's Wildmere heavy oil sites is the surface location for one to four wells. Every pad is equipped to operate independently and, as such, the risk of a single event resulting in a material production loss is mitigated. Solution gas is pipeline connected through most of the field allowing wells to share gas for tank heating, to sell gas, or to deliver purchased gas if desired in order to offset propane otherwise used for tank heating. All Wildmere oil production is tank treated to produce sales quality oil before being trucked to sales points.

In 2010, Gear began investigating secondary and tertiary recovery alternatives for the Lloydminster reservoir by cutting core and initiating a variety of lab-scale experiments. Testing, numerical reservoir simulation and economic evaluations through 2011 led to a decision to initiate a horizontal polymer flood pilot. In September 2012, a five horizontal well pilot area commenced injection into two horizontal wells. Pressure monitoring on injectors and offset producers continues as expected with indications and early interpretation of response expected in the next two months. Results will be factored into revised expectations, and provided they are supportive, will influence the future design and capital deployment into commercial scale secondary or tertiary schemes on this resource.

During 2012, Gear drilled 33 gross (31.5 net) wells within the Wildmere area, all resulting in economic production. During 2013, Gear drilled 35 gross (30.9 net) wells with one being abandoned. In 2014, Gear plans to place a total of 21 additional wells. Approximately 85 per cent of the drilling is slated for low risk areas with proven Lloydminster or Cummings sands. The remaining locations accept moderately higher risk for the opportunity to materially extend the Cummings pool boundaries and add location inventory.

The GLJ Report assigns total proved plus probable reserves of 9.321 MMbbls of oil and NGLs and 0.377 Bcf of natural gas as at December 31, 2013 within the Wildmere area. The average production from the area for the fourth quarter of 2013 was 3,318 bbl/d.

Maidstone, Saskatchewan

The Maidstone property was acquired in December 2012 and is located primarily within Township 47 and Ranges 22 and 23 W3 and is approximately 57 kilometres southeast of Lloydminster Alberta. It is comprised of 2,560 gross (2,560 net) acres sections of lands. There are no material expiries expected as the majority of lands have been continued pursuant to the applicable tenure regulations.

Maidstone is characterized by unconsolidated Upper Mannville group clastic reservoirs with depths ranging from 500 meters to 650 meters. While the Cummings formation has been the most exploited interval, Sparky, Waseca and Mclaren all hold significant potential as future development targets on Gear acreage.

Consistent with Gear's other heavy oil sites, each one to five well pad is equipped to operate independently and as such, the risk of a single event culminating into a material production loss is mitigated. Solution gas is used to heat production tanks and to date, left-over gas volumes are not significant enough to warrant a gas gathering system; however, Gear has readied itself for that possibility by surveying the pipeline route. All Maidstone oil production is tank treated to produce sales quality oil before being trucked to sales points.

In 2013 Gear drilled nine gross (nine net) wells in the area. Early production results are encouraging and supportive of continued activity. In 2014, 20 wells are planned to test and advance a variety of Mannville intervals.

The GLJ Report assigns total proved plus probable reserves of 2.426 MMbbls of heavy oil at December 31, 2013 within the Maidstone area. The average production from the area for the fourth quarter of 2013 was 550 bbl/d.

Other Areas

The Corporation held interests in a number of wells and lands in other portions of Alberta, British Columbia and Saskatchewan at December 31, 2013. In 2013 Gear drilled 2 gross (2 net) wells in these areas. Gear has participated in one non-operated drill with a net working interest of 15 per cent. At December 31, 18,800 net acres have expired and 7,400 net acres have been continued pursuant to the applicable tenure regulations. Gear may drill up to 18 locations in the other areas in 2014.

The GLJ Report assigns total proved plus probable reserves of 1,332 Mbbls of oil and NGLs and 15.106 Bcf of natural gas as at December 31, 2013 within these other areas. The total average production from these areas for the fourth quarter of 2013 was 774 bbl/d.

Oil and Gas Wells

The following table sets forth the number and status of oil and gas wells in which the Corporation 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	236.0	208.7	201.0	188.1	49.0	44.7	63.0	56.7
British Columbia	-	-	-	-	1.0	0.7	7.0	6.5
Saskatchewan	18.0	16.2	5.0	5.0	8.0	8.0	63.0	62.5
Total	254.0	224.9	206	193.1	58.0	53.4	133.0	125.7

Note:

(1) This table does not include water source wells, injection wells, abandoned wells or wells which have never produced. Producing wells are based on public data status.

Land Holdings Including Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2013.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	68,593	58,768	28,645	26,040	97,238	84,808
British Columbia	5,475	4,875	26,768	26,168	32,243	31,043
Saskatchewan	36,643	32,258	7,473	7,473	44,116	39,731
Total	110,711	95,901	62,886	59,681	173,597	155,582

Gear calculates both its gross and net acres on a per lease basis.

The Corporation expects that rights to explore, develop and exploit 15,058 net acres of its undeveloped land holdings may expire by December 31, 2014, a portion of which may be continued by drilling. Gear plans to drill or submit application to continue selected portions of the above acreage.

Forward Contracts and Marketing

Most of Gear's crude oil and all natural gas production is sold to major marketers on prearranged terms with indexing to published spot pricing. In a typical month, Gear splits the sale of its crude oil between five separate purchasers, three purchasers at railway terminals and two at pipeline connected terminals. Dependent upon price expectations, the Corporation targets between 35 per cent and 65 per cent of its crude oil to be sold into railway terminals. Gear's most dominant pipeline connected purchaser has provided the Corporation with a parental guarantee for payment of US$12 million to cover any payments owing by the purchaser for crude oil delivered. Gear’s established method of mitigating counter party risk is to accept pre-payment on oil deliveries from smaller purchasers or those with less established credit ratings.

The contract term is generally a 30-day evergreen in the case of pipeline connected crude oil buyers and up to one year for natural gas and natural gas liquids. For crude oil purchaser contracts at rail terminals, Gear generally enters into volume based purchase contracts with 1 to 6 month terms. None of Gear’s purchase agreements currently contain material non-performance penalties.

Gear may periodically hedge the price of a portion of its crude oil and natural gas production. The Corporation has no firm gas transportation contracts.

As of the date hereof, the Corporation has the following crude oil and natural gas financial derivatives in place:

Canadian Dollar Denominated Financial WTI Crude Oil Contracts					
Term		**Contract**	**Volume bbl/d**	**Sold Swap CAD/bbl**	**Sold Put CAD/bbl**
January 1, 2014	June 30, 2014	3-way enhanced swap	1,800	98.02	75.00
July 1, 2014	December 31, 2014	3-way enhanced swap	1,000	99.81	75.00

US Dollar Denominated Financial WTI Crude Oil Contracts						
Term		**Contract**	**Volume bbl/d**	**Sold Call USD/bbl**	**Bought Put USD/bbl**	**Sold Put USD/bbl**
July 1, 2014	December 31, 2014	3-way collar	600	98.36	80.00	65.00

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation uses its internal historical and current costs to estimate its abandonment and reclamation costs when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. The costs are estimated on an area by area basis. The Corporation has approximately 695.1 net wells including water source, injection and standing wells for which it expects to incur abandonment and reclamation costs. The abandonment and reclamation obligation included in the Corporation's financial statements differs from the amount deducted in the reserves evaluation, as the GLJ Report forecasts abandonment costs only for existing and undeveloped reserves wells, and no allowance was made for reclamation of existing well sites or the abandonment and reclamation of any facilities in the GLJ Report. The following table sets forth abandonment costs deducted in the estimation of the Corporation's future net revenue as provided in the GLJ Report:

Forecast Prices and Costs (M$)

Year	Total Proved Abandonment Costs (Undiscounted)	Total Proved plus Probable Abandonment Costs (Undiscounted)
2014	-	-
2015	-	-
2016	-	-
Thereafter	5,582	7,643
Total Undiscounted	5,582	7,643
Total Discounted @ 10%	1,003	1,010

The asset retirement obligations recorded in the Corporation's financial statements result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Corporation estimates the total undiscounted amount of cash flows required to settle its asset retirement obligation is approximately $43.5 million, which will be incurred over the next 26 years.

Tax Horizon

Based on current forward commodity prices, the Corporation does not expect to pay current income tax for the 2014 fiscal year. There are multiple factors which impact the tax horizon of the Corporation, the most notable being production, commodity prices and capital spending levels. Gear currently recognizes a deferred tax asset as current tax pools exceed the book value of property, plant and equipment.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2013:

	(M$)
Property Acquisition Costs	
Proved properties	108
Undeveloped properties	-
Exploration costs	3,146
Development costs	50,413
Dispositions	(200)
Total	53,467

Exploration and Development Activities

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

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Oil	-	-	-	-
Heavy Oil	-	-	46.0	41.4
Natural Gas	-	-	-	-
Dry	-	-	1.0	0.6
Service/Other	-	-	-	-
Stratigraphic Test	-	-	-	-
Total	-	-	47.0	42.0

See "*Statement of Reserves Data and Other Oil and Gas Information – Principal Properties*" for a description of the Corporation's exploration and development plans.

A major exploration and development area for Gear in 2014 will continue to be the Wildmere area in Alberta. Gear will devote a large portion of 2014 capital into low risk horizontal drilling opportunities targeting the Lloydminster formation. Also within Wildmere, the Cummings formation will be further developed and expanded throughout 2014 with seven wells planned for the 2014 drilling program. In the Maidstone area of Saskatchewan, Gear drilled nine wells in 2013, and plans to more than double area activity in this low royalty area during 2014.

The majority of capital expenditures in 2014 will be invested in these three plays. See "*Statement of Reserves Data and Other Oil and Gas Information – Principal Properties*".

Production Estimates

The following tables disclose, by product, and by area, the total volume of the Corporation's gross production estimated by GLJ for 2014 in the estimates of future net revenue from gross proved and gross probable reserves disclosed under "*Disclosure of Reserves Data*".

From Gross Proved Reserves:	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	BOE (BOE/d)	%
Wildmere	-	3,239	17	-	3,242	68.0
Other	-	1,378	841	11	1,529	32.0
Total	-	4,617	858	11	4,771	100.0

From Gross Probable Reserves:	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE	%
	(bbls/d)	(bbls/d)	(Mcf/d)	(bbls/d)	(BOE/d)	
Wildmere	-	214	0	-	214	41.0
Other	-	302	35	1	308	59.0
Total	-	516	35	1	522	100

Production History

The following tables summarize certain information in respect of production (which includes royalty interest volumes), product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	2013			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[1]				
Light and Medium Crude Oil (bbls/d)	-	3	5	16
Heavy Oil (bbls/d)	4,356	3,639	3,658	3,416
Gas (Mcf/d)	1,641	1,723	1,672	1,995
NGLs (bbls/d)	13	10	5	13
Combined (BOE/d)	4,642	3,940	3,947	3,777
Average Price Received (net of transportation)				
Light and Medium Crude Oil ($/bbl)	-	99.62	88.15	70.69
Heavy Oil ($/bbls)	62.95	88.11	71.73	53.81
Gas ($/Mcf)	3.12	2.53	3.66	3.13
NGLs ($/bbls)	49.61	50.89	51.81	45.42
Combined ($/BOE)	60.31	82.70	68.19	50.69
Royalties Paid				
Light and Medium Crude Oil ($/bbls)	-	-	-	-
Heavy Oil ($/bbls)	16.10	20.03	17.25	11.85
Gas ($/Mcf)	0.01	0.14	0.34	0.30
NGLs ($/bbls)	3.54	3.22	1.91	1.45
Combined ($/BOE)	15.15	18.59	16.16	10.93

	2013			
	Dec. 31	Sept. 30	June 30	Mar. 31
Operating Expenses ($/BOE)				
Light and Medium Crude Oil ($/bbls)	-	-	-	-
Heavy Oil ($/bbls)	16.67	17.04	18.90	19.06
Gas ($/Mcf)	2.92	3.25	3.74	2.85
NGLs ($/bbls)	16.67	17.04	18.90	19.06
Combined ($/BOE)	16.72	17.21	19.13	18.81
Netback Received ($/BOE)(2)				
Light and Medium Crude Oil ($/bbls)	-	99.62	88.15	70.69
Heavy Oil ($/bbls)	30.18	51.04	35.58	22.90
Gas ($/Mcf)	0.19	(0.86)	(0.42)	(0.02)
NGLs ($/bbls)	29.40	30.63	31.00	24.91
Combined ($/BOE)	28.44	46.90	32.90	20.95

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties, and operating and transportation costs from revenues.

The following table indicates the Corporation's company interest average daily production from its important areas for the year ended December 31, 2013:

	Light and Medium Crude Oil (bbls/d)	Heavy Oil (bbls/d)	Gas (Mcf/d)	NGLs (bbls/d)	BOE (BOE/d)
Wildmere	-	3,100	7	-	3,107
Other	6	669	1,750	10	972
Total	6	3,769	1,757	10	4,079

The Corporation's production for the year ended December 31, 2013 was 93 per cent heavy oil and 7 per cent natural gas.

For the twelve months ended December 31, 2013, approximately 98 per cent of the Corporation's gross revenue was derived from crude oil and liquids production and 2 per cent was derived from natural gas production.

DIVIDEND POLICY

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

In addition to the foregoing, the Corporation's ability to pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness that the Corporation has incurred or may incur in the future including the terms of the Gear Credit Facilities. The Gear Credit Facilities prohibits the Corporation from declaring or paying any dividends to any of its shareholders if: (i) a demand has been made on the Gear Credit Facilities; (ii) if declaring or paying the dividend would result in a default under the Gear Credit Facilities; or (iii) during the continuance of a borrowing base shortfall, which is the amount by which the aggregate of all outstanding obligations under the Gear Credit Facilities exceeds the then current borrowing base of the Gear Credit Facilities as a result of a reduction or redetermination of the borrowing base, (until cured).

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Common Shares, an unlimited number of Preferred Shares, issuable in series, and an unlimited number of Series 1 Preferred Shares, of which 54,085,199 Common Shares and no Series 1 Preferred Shares are currently issued and outstanding. The following is a description of the rights, privileges, restrictions and conditions attaching to the Common Shares, the Preferred Shares and the Series 1 Preferred Shares of the Corporation.

Common Shares

The Corporation has an unlimited number of Common Shares authorized. The holders of Common Shares are entitled to: dividends if, as and when declared by the Board; to vote at any meetings of the holders of Common Shares of the Corporation; and upon liquidation, dissolution or winding up of the Corporation, receive the remaining property and assets of the Corporation. All of the Common Shares outstanding are fully paid and non-assessable.

Preferred Shares

Gear is authorized to issue an unlimited number of Preferred Shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board of Gear prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding up of Gear, whether voluntary or involuntary, the Preferred Shares are entitled to preference over the Common Shares and any other shares ranking junior to the Preferred Shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the Preferred Shares as may be determined at the time of creation of such series.

Series 1 Preferred Shares

At the date hereof, Gear has created Series 1 Preferred Shares; however, no Series 1 Preferred Shares are outstanding. The holders of Series 1 Preferred Shares are not entitled to receive notice of, attend nor vote at any meetings of the shareholders of the Corporation. Subject to the provisions of any other series of Preferred Shares created after the date of the creation of the Series 1 Preferred Shares, the holders of Series 1 Preferred Shares are entitled to receive, if, as and when declared by the Board, any dividends declared by the Board. Any dividends declared and paid on the Common Shares must also be declared and paid on the Series 1 Preferred Shares, which shall be in priority to the holders of the Common Shares. In the event of liquidation, dissolution or winding-up of the Corporation or any other distribution of assets of the Corporation among its shareholders for the purposes of winding up the affairs of the Corporation, the Series 1 Preferred Shares shall rank in priority to the Common Shares in a sum equivalent to the value of the Series 1 Preferred Shares; provided that the amount to be received by the Series 1 Preferred Shares will be equivalent to the amount to be received per Common Share upon such liquidation, dissolution or winding up and subject to the provisions of any other series of Preferred Shares created after the date of the creation of the Series 1 Preferred Shares.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares are listed and posted for trading on the TSX under the symbol "GXE". The following table sets forth the high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares on the TSX as reported by the TSX for the periods indicated since the commencement of trading of the Common Shares on November 18, 2013:

Period	Price Range ($) High	Low	Trading Volume
2013			
November (18-30)	3.29	2.55	6,392,361
December	3.55	3.05	4,816,495
2014			
January	3.57	3.12	10,393,493
February	4.01	3.18	6,047,522
March (1 to 20)	4.29	3.89	6,068,085

Prior Sales

The following table sets forth the Common Shares issued (or securities convertible into Common Shares) in the 12-month period prior to the date of this Annual Information Form:

Date	Number of Common Shares	Issue Price Per Share ($)	Aggregate Issue Price ($)	Nature of Consideration
March 25, 2013	105,000	2.50	-	Options(1)
April 1, 2013	97,935	2.50	224,838	Common Shares(2)
May 7, 2013	90,000	2.50	-	Options(3)
October 10, 2013	90,000	3.00(6)	-	Options(4)(5)
October 16, 2013	80,000	3.00(6)	-	Options(4)(5)
March 7, 2014	23,666	2.50	59,165	Common Shares(6)
March 10, 2014	105,217	2.50	263,043	Common Shares(6)

Notes:

(1) Options were issued to Mr. Bay upon joining the Board.
(2) In connection with payment of the bonuses earned for the year ended December 31, 2012, certain executive officers of the Corporation were entitled to elect to receive up to 25 per cent of the cash amount of their bonus subject to a 1.25 multiple in the form of Common Shares. All Common Shares forming a part of this bonus election were issued from treasury on April 1, 2013 at a price of $2.50 per Common Share.
(3) Represents the aggregate number of Options issued to a new employee and a new consultant of the Corporation.
(4) Represents the aggregate number of Options issued to new employees of the Corporation.
(5) The exercise price for the Options was calculated using the weighted average trading price of the Common Shares on the TSX for the first twenty (20) trading days following the listing of the Common Shares on the TSX to certain employees.
(6) Represents options exercised by employees of the Corporation.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of management of the Corporation, none of the securities of the Corporation are held in escrow or are subject to a contractual restriction on transfer as at the date hereof.

DIRECTORS AND EXECUTIVE OFFICERS

Name, Occupation and Security Holding

The following table sets forth certain information in respect to Gear's directors and executive officers:

Name, Province and Country of Residence	Position(s) with Gear	Principal Occupation During the Five Years Preceding
Don T. Gray[(1)(2)(3)] Alberta, Canada	Chairman since January 2010 and a Director since February 2009	Private investor; a director of the Corporation since February 2009 and Chairman of the Corporation since January 2010; a founding partner and President of EIQ Capital Corp., a private capital management company from May 2007 to September 2013; Chairman of the Board of Petrus Resources Ltd., a private oil and gas company, since 2010; prior thereto, Mr. Gray was the Chief Executive Officer of Peyto Exploration & Development Corp. (formerly Peyto Energy Trust) ("**Peyto**") from August 2006 to January 2007; prior thereto, Mr. Gray was the President and Chief Executive Officer of Peyto from October 1998 to August 2006.
Peter Verburg[(1)(3)] Alberta, Canada	Director since July 2009	A founding partner and President of EIQ Capital Corp., a private investment firm, since September 2013; prior thereto, Managing Director of EIQ Capital Corp. since March 2008; prior thereto Vice President, Investment Banking of GMP Securities L.P. since February 2005.
Greg Bay[(1)(3)] British Columbia, Canada	Director since March 2013	Founding partner, President of Cypress Capital Management Ltd., a private investment firm, from 1998 to present.
Raymond Cej[(1)(2)(3)] Alberta, Canada	Director since January 2013	President of Teine Energy Ltd., a private oil and gas company, since July 2010; President of Marble Point Energy Ltd. from January 2010 to July 2010; prior thereto, a senior executive for Shell Canada for 26 years.
Ingram Gillmore Alberta, Canada	President, Chief Executive Officer since May 2010 and a Director since June 2010	President and Chief Executive Officer of the Corporation since May 2010; prior thereto Vice President, Engineering at ARC Resources Ltd. ("**ARC**") since January 2007; prior thereto, Manager Engineering since 2005.
David Hwang Alberta, Canada	Vice President, Finance and Chief Financial Officer since June 2011	Vice President, Finance of Gear since June 2011; prior thereto, controller at ARC since 2010 and, prior thereto, manager at ARC since 2006.
Yvan Chretien Alberta, Canada	Vice President, Land since September 2010	Vice President, Land of Gear since September 2010; prior thereto, Vice-President, Land at ARC from 2006 to March 2010.
Tom Everest Alberta, Canada	Vice President, Engineering since May 2010	Vice President, Engineering of the Corporation since May 2010. Manager, exploitation at BMEC from July 2008 to January 2010. Prior thereto, senior engineer with Enerplus Resources Fund from January 2008 to June 2008.
Jason Kaluski Alberta, Canada	Vice President, Operations since March 2011	Vice President, Operations of Gear since March 2011; prior thereto, manager of operations for Questerre Energy Corporation from 2008 to 2011.
James Lord Alberta, Canada	Vice President, Business Development since September 2010	Vice President, Business Development since September 2010; prior thereto, senior business development engineer at NAL Resources Management Limited from 2009 to 2010 and senior engineer of Alberta Clipper Energy Inc. from 2005 to 2009.

Name, Province and Country of Residence	Position(s) with Gear	Principal Occupation During the Five Years Preceding
Jay P. Reid Alberta, Canada	Corporate Secretary since November 2011	Partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 1990.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation and Governance Committee.
(4) Gear does not have an Executive Committee.
(5) Gear's directors will hold office until the next annual general meeting of the Corporation's shareholders or until each director's successor is appointed or elected pursuant to the ABCA.

As at the date of this Annual Information Form, the number of Common Shares beneficially owned, or controlled or directed, directly or indirectly, by all of the directors and officers of Gear is 6,824,301 Common Shares constituting approximately 12.62 per cent of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

Other than as disclosed below, to the knowledge of Gear, no director or executive officer of Gear (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Gear), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Mr. Cej was, prior to January 26, 2010, a trustee of Impax Energy Services Income Trust (the "**Trust**"). On December 14, 2009, the Trust filed for creditor protection in order to facilitate an orderly sale and wind-up of operations. On January 26, 2010, all of the trustees and directors of the Trust resigned following the sale of substantially all of the assets of the Trust. Upon the resignations of the trustees and directors, trading in the units of the Trust was suspended for failure to maintain a minimum number of directors as required under the rules of the TSX Venture Exchange.

Bankruptcies

To the knowledge of Gear, except as described above, no director or executive officer of Gear (nor any personal holding company of any of such persons) or shareholder holding a sufficient number of securities of Gear to affect materially the control of Gear: (a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Gear) 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 Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Penalties or Sanctions

To the knowledge of Gear, no director or executive officer of Gear (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Gear to affect materially the control of Gear, 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

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

None of the Corporation or any of its subsidiaries is a party to any legal proceeding nor was it a party to any legal proceeding during the financial year ended December 31, 2013, nor is the Corporation aware of any contemplated legal proceeding involving the Corporation or its subsidiaries or any of its property which involves a claim for damages exclusive of interest and costs that may exceed 10 per cent of the current assets of the Corporation.

Regulatory Actions

During the year ended December 31, 2013, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) any other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of any director or executive officer of the Corporation, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10 per cent of any class or series of the Corporation's outstanding voting securities, or any associate or affiliate of any of the foregoing persons or companies, in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or is reasonably expected to materially affect the Corporation, other than as disclosed elsewhere in this Annual Information Form. Jay Reid, the Corporate Secretary of Gear, is a partner of Burnet, Duckworth & Palmer LLP, which firm receives fees for legal services provided to Gear.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), the Corporation has not entered into any material contracts during the last financial year, or before the last financial year which are still in effect.

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are Deloitte LLP, the Corporation's independent auditors and GLJ, the Corporation's independent engineering evaluators.

Interests of Experts

To the Corporation's knowledge, there were no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of its associates or affiliates: (i) held by GLJ or by the "designated professionals" (as defined in Form 51-102F2 to National Instrument 51-102) of GLJ, when GLJ prepared the report, valuation, statement or opinion referred to herein as having been prepared by GLJ; (ii) received by GLJ or by the "designated professionals" of GLJ, after the time specified above; or (iii) to be received by GLJ or by the "designated professionals" of GLJ; except in each case for the ownership of Common Shares, which in respect of GLJ and GLJ's "designated professionals", as a group, has at all relevant times represented less than one percent of the outstanding Common Shares. In addition, neither GLJ, nor any director, officer or employee of GLJ, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

Deloitte LLP is independent of the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the Board of Directors is attached hereto as Schedule "C".

Composition of the Audit Committee

The audit committee (the "**Audit Committee**") is comprised of Messrs. Peter Verburg (Chair), Don T. Gray, Raymond Cej and Greg Bay. The following chart sets out the assessment of each of the proposed Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Don T. Gray Alberta, Canada	Yes	Yes	Mr. Gray holds a BSc in petroleum engineering from Texas A&M University and has over 25 years experience in the Canadian oil and gas business in various capacities. Mr. Gray is a Co-Founder and former President and Chief Executive Officer of Peyto and is also Chairman and co-founder of Petrus Resources Ltd., and Chairman of EIQ Capital Corp., a private investment company.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Peter Verburg Alberta, Canada	Yes	Yes	Mr. Verburg holds an MBA from the University of Calgary. He is currently the President of EIQ Capital Corp., a private investment company. He was formerly Managing Director of EIQ Capital since 2008, and prior thereto an officer at GMP Securities L.P., working in the Corporate Finance energy group since 2005.
Raymond Cej Alberta, Canada	Yes	Yes	Mr. Cej holds a Bachelor of Engineering from the Royal Military College and a Master of Engineering from the California Institute of Technology. He is currently President of Teine Energy Ltd., and brings with him over 35 years of industry experience in the oil and gas sector having held executive and director positions with companies in both the exploration and production side as well as in oilfield services.
Greg Bay Alberta, Canada	Yes	Yes	Mr. Bay obtained his chartered Financial Analyst Designation in 1988 and holds a Bachelor of Commerce in Finance from Brigham Young University. Mr. Bay is the President of Cypress Capital Management (founding partner) and brings with him over 25 years of experience in the investment industry with emphasis on the oil and gas sector. Mr. Bay also holds director positions with the Mullen Group Ltd., Santonia Energy Inc. and Hyperion Energy Corp.

Each of the members of the Audit Committee is considered "financially literate" and is considered "independent" within the meaning of NI 52–110.

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

Pre-Approval of Policies and Procedures

The Corporation has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by Deloitte LLP. The Audit Committee will approve the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, reoccurring or otherwise likely to be provided by Deloitte LLP during the current fiscal year and the Audit Committee will be informed of each non-audit service, as applicable. The list of services will be sufficiently detailed as to the particular services to be provided to ensure that the Audit Committee knows precisely what services it is being asked to pre-approve and it will not be necessary for any member of management to make a judgment as to whether a proposed service fits within pre-approved services.

External Auditors Service Fees

The following table summarizes the fees billed by the Corporation to its auditors, Deloitte LLP, for external audit and other services during the periods indicated:

Year	Audit Fees[1]	Audit -Related Fees[2]	Tax Fees[3]	All Other Fees[4]
	($)	($)	($)	($)
2013	130,101	-	52,854	61,793
2012	112,350	-	-	-

Notes:

(1) Represents the aggregate fees billed by the Corporation's external auditor in each of the last two fiscal years for audit services.
(2) Represents the aggregate fees billed in each of the last two fiscal years by the Corporation's external auditor for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements (and not reported under the heading "Audit Fees").
(3) Represents the aggregate fees billed in each of the last two fiscal years by the Corporation's external auditor for professional services for tax compliance, tax advice and tax planning.
(4) Represents the aggregate fees billed in each of the last two fiscal years by the Corporation's external auditor for products and services not included under the headings "Audit Fees", "Audit Related Fees" and "Tax Fees".

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* which received Royal Assent on June 29, 2012 (the "**Prosperity Act**"). In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can 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 NEB.

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

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

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

Alberta

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

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

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 per cent 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 per cent 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 per cent 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 per cent and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25 per cent and increase for every dollar of market price of oil increase above $55 up to 40 per cent 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 per cent of revenues reported from fee simple mineral title properties.

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

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5 per cent 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 per cent 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 per cent 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 per cent with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

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

British Columbia

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

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

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25 per cent.

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

- *Deep Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs;

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

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

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

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

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17m^3 per metre of depth for exploratory wildcat wells and less than 11m^3 per metre of depth for development wells and exploratory outpost wells.

The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000m^3; and

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

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

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

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

Saskatchewan

In Saskatchewan, the amount payable as 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 conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^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 per cent for all fourth tier oil, 10 per cent for heavy oil that is third tier oil or new oil, 12.5 per cent for southwest designated oil that is third tier oil or new oil, 15 per cent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20 per cent 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 per cent for all fourth tier oil, 25 per cent for heavy oil that is third tier oil or new oil, 35 per cent for southwest designated oil that is third tier oil or new oil, 35 per cent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45 per cent 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 per cent for all fourth tier gas, 15 per cent for third tier or new gas, and 20 per cent 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 per cent for all fourth tier gas, 35 per cent for third tier and new gas, and 45 per cent 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 per cent) and freehold tax rates (a freehold production tax rate of 0 per cent) 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 per cent) and freehold tax rates (a freehold production tax rate of 0 per cent) 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 per cent) and freehold tax rates (a freehold production tax rate of 0 per cent) 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 per cent) and freehold tax rates (a freehold production tax rate of 0 per cent) 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 per cent of gross revenues on EOR projects pre-payout and 20 per cent of EOR operating *income* post-payout and a freehold production tax of 0 per cent pre-payout and 8 per cent 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 per cent for oil produced prior to April 2013 and 2.25 per cent for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

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

Land Tenure

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

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

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

Federal

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

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 30, 2014, the AER is expected to assume the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

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

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

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

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

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

British Columbia

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

Saskatchewan

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

Liability Management Rating Programs

Alberta

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

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

- a 25 per cent increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);
- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);
- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and
- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

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

British Columbia

In British Columbia, the Commission implements the Liability Management Rating ("**LMR**") Program, designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the LMR Program, the Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Climate Change Regulation

Federal

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

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

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach and aims for a 50 per cent reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12 per cent of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are required to reduce their emissions intensity by 2 per cent from baseline in the fourth year of commercial operation, 4 per cent of their baseline in the fifth year, 6 per cent of their baseline in the sixth year, 8 per cent of their baseline in the seventh year and 10 per cent of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

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

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

British Columbia

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of CO_2 equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

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

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33 per cent reduction in the 2007 level of GHG emissions by 2020 and an 80 per cent reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. The *Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Recent amendments to the Cap and Trade Act repealed past requirements on public-sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under development.

Saskatchewan

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

RISK FACTORS

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

Exploration, Development and Production Risks

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

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

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

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

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

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 the Organization of the Petroleum Exporting Countries ("**OPEC**") and the ongoing global credit and liquidity concerns. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Prices, Markets and Marketing

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

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

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

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

Market Price of Common Shares

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Project Risks

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

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

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

Reliance on Key Personnel

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

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities and pipeline systems which it does not own and by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

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

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

Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

Operational Dependence

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

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

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

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See: "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Liability Management

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation' deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. This is of particular concern to junior oil and gas companies as they may be disproportionately affected by price instability. See: "*Industry Conditions*".

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with greenhouse gas ("**GHG**") emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17 per cent reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, Canadian/United States exchange rates could affect the future value of the Corporation's reserves as determined by independent evaluators.

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

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

Substantial Capital Requirements

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

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

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

Additional Funding Requirements

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

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

Credit Facility Arrangements

The Corporation currently has the Gear Credit Facilities and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under the Gear Credit Facilities which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding At this current moment, the Gear Credit Facilities carries a single covenant known as the "Current Ratio" (as defined in the Gear Credit Facilities) which limits the Corporations ability to borrow amounts greater than the facility limit. In the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Gear Credit Facilities, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Gear Credit Facilities, the lenders under the Gear Credit Facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Gear Credit Facilities may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

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

Issuance of Debt

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

Hedging

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

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

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

Title to Assets

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

Reserve Estimates

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

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

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

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

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

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

Insurance

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

Geopolitical Risks

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

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

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

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

Dividends

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

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Aboriginal Claims

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

Breach of Confidentiality

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

Income Taxes

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

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

Seasonality

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

Third Party Credit Risk

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

Conflicts of Interest

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

Expansion into New Activities

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

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown 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.

Hydraulic Fracturing

Currently the Corporation does not use hydraulic fracturing as a completion technique on its wells, however hydraulic fracturing is a common industry practice and is one that the Corporation may use in the future. Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

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

ADDITIONAL INFORMATION

Additional information relating to Gear may be found on SEDAR at www.sedar.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Gear's securities and securities authorized for issuance under equity compensation plans is contained in Gear's information circular – proxy statement relating to the Corporation's most recent annual meeting of shareholders that involved the election of directors.

Additional information is also provided in Gear's financial statements and management's discussion and analysis for the year ended December 31, 2013, which documents may be found on SEDAR at www.sedar.com.

SCHEDULE "A"

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

To the board of directors of Gear 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 provided 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 audited, evaluated and reviewed and reported on to the Company's board of directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	**Total**
GLJ Petroleum Consultants	Corporate Summary February 13, 2014	Canada	-	274,041	-	**274,041**

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

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

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 28, 2014

(Signed) "Caralyn P. Bennett"
Caralyn P. Bennett, P. Eng.
Vice President

SCHEDULE "B"

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

Management of Gear Energy Ltd. (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2013, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule "A" to this Annual Information Form.

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

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of such 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 the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;

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

(e) 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.

Per: (signed) "*Ingram Gillmore*"
Ingram Gillmore
President, Chief Executive Officer and Director

Per: (signed) "*David Hwang*"
David Hwang
Vice President, Finance and Chief Financial Officer

Per: (signed) "*Donald T. Gray*"
Donald T. Gray
Director

Per: (signed) "*Raymond Cej*"
Raymond Cej
Director

March 18, 2014

SCHEDULE "C"

GEAR ENERGY LTD.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Gear Energy Ltd. ("**Gear**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the following:

1. nature and scope of the annual audit;

2. the oversight of management's reporting on internal accounting standards and practices;

3. the review of financial information, accounting systems and procedures;

4. financial reporting and financial statements,

and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

5. To assist directors of Gear ("**Directors**") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

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

7. To enhance the external auditor's independence;

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

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

MEMBERSHIP OF COMMITTEE

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

11. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

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

13. For the purposes of this Mandate, "financially literate" has the meaning ascribed thereto in NI 52-110 and means that the member has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

MANDATE AND RESPONSIBILITIES OF COMMITTEE

It is the responsibility of the Committee to:

14. Oversee the work of the external auditors, including the resolution of any disagreements between Management and the external auditors regarding financial reporting.

15. Satisfy itself on behalf of the Board with respect to Gear's internal control systems identifying, monitoring and mitigating business risks; and ensuring compliance with legal, ethical and regulatory requirements.

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

- reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
- reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
- reviewing accounting treatment of unusual or non-recurring transactions;
- ascertaining compliance with covenants under loan agreements;
- reviewing disclosure requirements for commitments and contingencies;
- reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
- reviewing unresolved differences between Management and the external auditors; and
- obtain explanations of significant variances with comparative reporting periods.

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

18. With respect to the appointment of external auditors by the Board:

- recommend to the Board the external auditors to be nominated;
- recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
- on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
- when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

- review and pre-approve any non-audit services to be provided to Gear 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.

19. Review with external auditors (and internal auditor if one is appointed by Gear) their assessment of the internal controls of Gear, 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 Gear and its subsidiaries.

20. Review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance).

21. Establish a procedure for:

- the receipt, retention and treatment of complaints received by Gear regarding accounting, internal accounting controls or auditing matters; and

- the confidential, anonymous submission by employees of Gear of concerns regarding questionable accounting or auditing matters.

22. Review and approve Gear's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Gear. All employees of Gear are to cooperate as requested by the Committee.

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

Meetings and Administrative Matters

8. 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.

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

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

11. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of Gear will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

12. 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.

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

14. The Committee may invite such officers, directors and employees of the Corporation 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.

15. Minutes of the Committee will be recorded and maintained and circulated to Directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

16. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation as determined by the Committee.

17. 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.

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

19. Nothing contained in this mandate is intended to expand applicable standards of liability under statutory, regulatory, common law or any other legal requirements for the Board or members of the Committee. The Committee may adopt additional policies and procedures as it deems necessary from time to time to fulfill its responsibilities.

November 12, 2013