YANGARRA RESOURCES LTD.

ANNUAL INFORMATION FORM

April 17, 2013

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ABBREVIATIONS

Abbreviations

Oil and Natural Gas Liquids		Natural Gas	
Bbl or bbl	Barrel	Mcf or mcf	thousand cubic feet
Bbls or bbls	Barrels	Mmcf	million cubic feet
Mbbl	thousand barrels	Mcf/d or mcf/d	thousand cubic feet per day
Mmbbl	million barrels	MMcf/d	million cubic feet per day
Mstb	thousand stock tank barrels	Mbtu/d	thousand British Thermal Units per day
Bbl/d or bbl/d	barrels per day	MMBTU or mmbtu	million British Thermal Units
BOPD or bopd	barrels of oil per day	Bcf or bcf	billion cubic feet
NGLs	natural gas liquids	GJ	Gigajoule

Other

BOE or boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 Bbl of crude oil for 6 Mcf of natural gas. *Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*
BOE/d, boe/d or boepd	barrel of oil equivalent per day

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated and M or M$ means thousands of dollars.

FORWARD-LOOKING STATEMENTS

Certain information contained in this Annual Information Form constitutes forward-looking statements and forward-looking information within the meaning of applicable securities legislation. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "believe", "intend", "forecast", "plans", "guidance" and similar expressions is intended to identify forward-looking statements or information.

More particularly and without limitation, this Annual Information Form and the documents incorporated by reference herein contain forward-looking statements and information relating to the following:

- the performance characteristics of the Corporation's oil, NGLs and natural gas properties;
- oil, NGLs and natural gas production levels;
- the size of the oil, NGLs and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- future funds from operations;
- capital programs;
- debt levels;
- future royalty rates;
- future depletion, depreciation and accretion rates;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditure programs.

The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are based on certain key expectations and assumptions made by the Corporation, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities and the availability and cost of labour and services.

Although the Corporation believes that the expectations reflected in the forward-looking statements and information in this Annual Information Form and in the documents incorporated by reference herein are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to the risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources, changes in tax, royalty and environmental legislation and the risks under the heading "Risk Factors" in this Annual Information Form. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Readers are cautioned that the foregoing list of factors and risks is not exhaustive.

The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are made as of the date hereof and, unless so required by applicable law, the Corporation undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise. The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are expressly qualified by this cautionary statement.

READER ADVISORY

On April 28, 2010 the Corporation consolidated its Common Shares on a five old Common Shares for one new Common share (5:1) basis (the "**Consolidation**"). All references to number and value of Common Shares of the Corporation in this Information Circular are presented on a pre-consolidation basis unless noted otherwise.

INCORPORATION AND ORGANIZATION

Yangarra Resources Ltd. (the "**Corporation**" or "**Yangarra**") was formed on May 1, 2010 as a result of an amalgamation under the *Business Corporations Act* (Alberta) ("**ABCA**") between Yangarra and its wholly owned subsidiary, Athabaska Energy Ltd. The Corporation's predecessor entity, also called Yangarra Resources Ltd., was formed on November 9, 2005 as a result of an amalgamation under the ABCA between TriOil Ltd. ("**TriOil**") and Yangarra Resources Inc. ("**Yangarra Predecessor**"). Effective on December 31, 2009, Yangarra Predecessor acquired all of the issued and outstanding shares of Athabaska Energy Ltd. ("Athabaska") by issuing 50,000,004 common shares in the capital of Yangarra Predecessor at a deemed price of $0.05 per share (the "**Athabaska Acquisition**").

TriOil was incorporated under the ABCA under the name "1000863 Alberta Ltd." and changed its name to "TriOil Ltd." and amended its share capital to add first and second preferred shares on September 26, 2002. TriOil amended its articles to remove its "private company" restrictions on November 13, 2002. Effective on August 13, 2004, TriOil amalgamated with Entrada Energy Inc. and continued to operate under the name "TriOil Ltd.".

Yangarra Predecessor was incorporated under the ABCA under the name "324220 Alberta Ltd" and changed its name to "Ayrex Resources Ltd" on August 20, 1985. Yangarra Predecessor consolidated its share capital on a four for one basis on May 6, 2003, and changed its name to "Yangarra Resources Inc." on June 16, 2003. Yangarra Predecessor amended and registered its restated articles to include an unlimited number of common shares and preferred shares on April 30, 2004.

The Corporation's head office and registered office is located at Suite 1530, 715 - 5th Avenue S.W., Calgary, Alberta, T2P 2X6.

The Corporation has one wholly-owned subsidiary, "Yangarra Resources Corp." incorporated under the ABCA.

BUSINESS OF THE CORPORATION

General

Yangarra is a growth oriented, exploration focused oil and natural gas company. The Corporation is involved in the production, exploration and development of resource properties in the Central Alberta, Medicine Hat and Jaslan areas of Alberta. For the year ended December 31, 2012, Yangarra's oil and gas assets produced approximately 1,915 boe/d of oil, natural gas and NGLs. As at the date hereof, Yangarra's oil and gas assets produce approximately 2,500 boe/d of oil, natural gas and NGLs. Yangarra owns approximately 108,806 gross (100,569 net) acres of undeveloped land. See "Statement of Reserves Data and Other Oil and Gas Information" in this Annual Information Form.

Three Year History

On March 17, 2010, the Corporation completed a non-brokered private placement of 80,000,000 Common Share units ("**Common Share Units**") at a price of $0.075 per Common Share Unit, for gross proceeds of $6,000,000. Each Common Share Unit consisted of one Common Share and one-half of one Common Share purchase warrant. Each whole Common Share purchase warrant is exercisable anytime up to March 15, 2012, at a price of $0.10 per Common Share, subject to certain earlier termination provisions.

On April 28, 2010 the Corporation completed the Consolidation on a 5 for 1 basis.

On May 1, 2010, the Corporation amalgamated with its wholly-owned subsidiary, Athabaska under the name "Yangarra Resources Ltd.".

On May 25, 2010, the Corporation completed a non-brokered private placement of 3,745,454 post-consolidation Common Shares at a price of $0.55 per post-consolidation Common Share issued on a "flow-through" basis under the *Income Tax Act* (Canada) for aggregate gross proceeds of $2,060,000.

On June 28, 2010, the Corporation completed a private-placement of 1,650,000 post-consolidation Common Shares at a price of $0.60 per post-consolidation Common Share issued on a "flow-through" basis under the *Income Tax Act* (Canada) and 1,650,000 post-consolidation Common Shares at a price of $0.56 per post-consolidation Common Share, for aggregate gross proceeds of $1,914,000.

On October 25 and 28, 2010, the Corporation completed a private placement of 10,000,000 Common Share Special Warrants at a price of $0.65 per Common Share Special Warrant for gross proceeds of $6.5 million and 8,666,667 Flow-Through Special Warrants at a price of $0.75 per Flow-Through Special Warrant, for gross proceeds of $6.5 million, such that the aggregate gross proceeds of the offering (the "**Offering**") of Common Share Special Warrants and Flow-Through Special Warrants (collectively the "**Special Warrants**") was $13 million. Each Special Warrant entitled the holder thereof to receive one post-consolidation Common Share on the exercise or deemed exercise of the Special Warrant, as applicable, subject to adjustment in certain events. The Special Warrants were exercisable by the holder at any time after the closing of the Offering for no additional consideration and all unexercised Special Warrants were deemed to be exercised on the earlier of (a) four months and a day following the closing of the Offering, and (b) the fifth day after a receipt was issued for a final prospectus by or on behalf of the securities regulatory authorities in each of the provinces of Canada where the Special Warrants were sold qualifying the post-consolidation Common Shares to be issued upon the exercise of the Special Warrants, as applicable. If the principal securities regulator had not issued a receipt for the final prospectus on or before November 30, 2010, the holder of each Common Share Special Warrant would have been entitled to receive 1.1 post-consolidation Common Shares in lieu of one post-consolidation Common Share upon exercise of Special Warrants. The principal securities regulator issued a receipt for the final prospectus on November 22, 2010.

On March 8, 2011 the Company, closed a "bought deal" financing, completed by way of a short form prospectus, for the sale of 23,632,500 Common Shares at a price of $0.73 per share for gross proceeds of $17,251,725.

On March 8, 2011, the Corporation redeemed preferred shares for $1,000,000 cash plus outstanding dividends payable.

On June 23, 2011 the Corporation, closed a "bought deal" financing, completed by way of private placement, for the sale of 12,500,000 Common Shares on a flow through basis at a price of $0.80 per share for gross proceeds of $10,000,000.

Significant Acquisitions

In March 2011, the Corporation purchased a 15% overriding royalty on natural gas and a 5-15% sliding scale overriding royalty on oil that covered approximately eleven sections of Cardium and Glauconitic perspective land in the Willesden Green area. No Business Acquisition Report was filed on SEDAR regarding the acquisition, as the acquisition was not a “significant acquisition” as such term is defined under Part 8 of the National Instrument 51-102 *Continuous Disclosure Obligations*.

During the financial year ended December 31, 2010, the Corporation also purchased assets in the Willesden Green/Ferrier area of Alberta, for a purchase price of approximately $4,000,000. No Business Acquisition Report was filed on SEDAR regarding the acquisition, as the acquisition was not a “significant acquisition” as such term is defined under Part 8 of the National Instrument 51-102 *Continuous Disclosure Obligations*.

DESCRIPTION OF THE BUSINESS

Strategy

Yangarra plans to grow over the next five years by drilling its extensive Cardium, Glauconitic, Rock Creek and Viking assets in Central Alberta. Longer term development includes the Second White Specs and Duvernay plays.

Yangarra's business plan is to focus on sustainable and profitable per share growth in both cash flow from operations and net asset value. To accomplish this, the Corporation will focus on enhancing its asset base through selective land acquisitions, exploratory drilling and development drilling.

The Corporation expects to internally generate exploration and development opportunities possessing medium risk and multiple prospective productive zone potential with a prudent exposure to higher risk/reward prospects. The Corporation intends to maintain a balance between exploration, development and exploitation drilling, combined with selective acquisition opportunities that meet the Corporation's business parameters. To achieve sustainable and profitable growth, the Corporation will control the timing and costs of its projects wherever possible. Accordingly, the Corporation will seek to become the operator of its properties to the greatest extent possible. Further, to minimize competition within its geographic areas of interest, the Corporation will, after giving consideration to its risk profile, strive to maximize its working interest ownership in its properties. While the Corporation intends to have the skills and resources necessary to achieve its objectives, participation in exploration and development in the oil and natural gas industry has a number of inherent risks. See "Risk Factors".

In reviewing potential drilling or acquisition opportunities, the Corporation gives consideration to the following criteria:

(a) risk capital required to secure or evaluate the investment opportunity;

(b) the potential return on the project, if successful;

(c) the likelihood of success; and

(d) the risked return versus cost of capital.

In general, the Corporation will use a portfolio approach in developing a large number of opportunities with a balance of risk profiles and commodity exposure, in an attempt to generate sustainable high levels of profitable production and financial growth.

Price Risk Management

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

(a) world market forces, including the ability of OPEC to set and maintain production levels and prices for crude oil;

(b) political conditions, including the risk of hostilities in the Middle East and other regions throughout the world;

(c) increases or decreases in crude oil quality and market differentials;

(d) availability of takeaway pipeline capacity

(e) the impact of changes in the exchange rate between Canada and U.S. dollars on prices received by the Corporation for its crude oil and natural gas;

(f) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;

(g) global and domestic economic and weather conditions;

(h) price and availability of alternative fuels; and

(i) the effect of energy conservation measures and government regulations.

Revenue Sources

For the year ended December 31, 2012, 77% of the revenue from Yangarra's properties before royalties was derived from oil and NGLs and 23% was derived from natural gas. Production is sold to marketers at delivery points in or close to the producing field.

Need to Replace and Grow Reserves

The future oil and natural gas production of the Corporation and therefore future cash flows, are highly dependent upon ongoing success in exploring on the Corporation’s current and future undeveloped land base, exploiting the current producing properties and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted.

The business of discovering, developing, or acquiring reserves is capital intensive. To the extent cash flows from the Corporation’s operating activities are insufficient and external sources of capital become limited or unavailable, the ability for the Corporation to make the necessary capital investments to maintain and expand its oil and natural gas reserves may be impaired. There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves to replace and grow production at acceptable costs.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. The Corporation will actively compete for capital, skilled personnel, undeveloped land, reserves acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

Personnel

As at December 31, 2012, Yangarra had 19 employees (14 head office & 5 field). As at the date hereof, Yangarra has 17 employees (11 head office & 6 field).

Bankruptcy and Similar Procedures

On October 7, 2009, the Corporation filed the Restructure Proposal with its creditors to restructure under Part III Division I of the *Bankruptcy and Insolvency Act* (Canada). See "Business of the Corporation – Relevant Three Year History" of this Annual Information Form.

Reorganizations

On October 7, 2009, the Corporation filed the Restructure Proposal with its creditors to restructure under Part III Division I of the *Bankruptcy and Insolvency Act* (Canada). See "Business of the Corporation – Relevant Three Year History" of this Annual Information Form.

On December 31, 2009, the Corporation completed the Athabaska Acquisition and on May 1, 2010, the Corporation amalgamated with its wholly-owned subsidiary, Athabaska under the name "Yangarra Resources Ltd.". See "Business of the Corporation – Relevant Three Year History" and of this Annual Information Form.

STATEMENT OF RESERVES DATA AND OTHER GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated March 27, 2013. The effective date of the Statement is December 31, 2012. All currency values are in Canadian dollars (unless otherwise specified).

The tables below summarize the Corporation's crude oil, natural gas liquids ("NGLs") and natural gas reserves and the present value of future net cash flows associated with such reserves, as December 31, 2012, as evaluated and prepared by Deloitte LLP ("Deloitte") independent petroleum engineers of Calgary, Alberta in the report dated March 27, 2013, based on forecasted price assumptions (the "2012 Reserves Report"). The 2012 Reserves Report has been prepared in accordance with the standards in the COGE Handbook and the reserves definitions set out by the Canadian Securities Administrators in National Instrument 51-101 and the COGE Handbook. The tables summarize the data contained in the 2012 Reserves Report and, as a result, may contain slightly different numbers than the 2012 Reserves Report due to rounding. All future cash flows are stated prior to provision for indirect costs and after deduction of royalties, estimated future capital expenditures and well abandonment costs. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The Corporation's crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided. In the various reserves related tables included herein, columns may not add due to rounding.

The Corporation is required to pay royalties to the Crown or other royalty owners and receives royalties from various working interest parties for commodities produced. Crown royalty payments are subject to change and any changes may have an adverse impact on the profitability of a project.

Attached as Schedule "A" to this Annual Information Form is the report on reserves data of Deloitte LLP and attached as Schedule "B" is the report of management and directors of the Corporation on the oil and gas reserves disclosure.

Petroleum and Natural Gas Reserves and Net Present Value

SUMMARY OF OIL AND GAS RESERVES
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2012

Reserves Category	**Light and Medium Oil (Mbbl)**			**Natural Gas Liquids (Mbbl)**			**Natural Gas (MMcf)**		
	W.I. Gross	Co.Share Gross	Net	W.I. Gross	Co.Share Gross	Net	W.I. Gross	Co.Share Gross	Net
Proved Developed Producing	585	597	541	388	467	358	6,617	7,907	6,859
Proved Developed Non-Producing	69	69	56	45	47	38	1,920	1,963	1,755
Proved Undeveloped	1,306	1,315	1,127	671	748	597	12,370	13,651	12,243
Total Proved	**1,960**	**1,981**	**1,725**	**1,103**	**1,261**	**992**	**20,907**	**23,521**	**20,856**
Probable	1,463	1,474	1,220	790	866	640	16,839	18,095	15,684
Total Proved Plus Probable	**3,423**	**3,455**	**2,945**	**1,893**	**2,127**	**1,632**	**37,746**	**41,616**	**36,540**

"**Working Interest Gross**" reserves are the Company's working interest (operating or non-operating) share before deducting royalty obligations and without including any royalty interests of the Company.
"**Company Share Gross**" reserves are the Company's working interest (operating or non-operating) share and before deducting royalty obligations but including any royalty interests of the Company.
"**Net**" reserves are the Company's working interest (operating or non-operating) share after deduction of royalty obligations plus any royalty interests of the Company.

SUMMARY OF NET PRESENT VALUES OF
FUTURE NET REVENUE
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2012

	Before Income Taxes				
Reserves Category	0.0% (M$)	5.0% (M$)	10.0% (M$)	15.0% (M$)	20.0% (M$)
Proved Developed Producing	62,538	52,393	45,271	40,034	36,034
Proved Developed Non-Producing	7,849	6,129	4,992	4,196	3,611
Proved Undeveloped	93,186	66,771	49,387	37,300	28,516
Total Proved	**163,573**	**125,293**	**99,650**	**81,530**	**68,161**
Probable	154,123	98,132	67,731	49,523	37,731
Total Proved Plus Probable	**317,696**	**223,425**	**167,381**	**131,053**	**105,892**

	After Income Taxes				
Reserves Category	0.0% (M$)	5.0% (M$)	10.0% (M$)	15.0% (M$)	20.0% (M$)
Proved Developed Producing	62,538	52,393	45,271	40,034	36,034
Proved Developed Non-Producing	7,849	6,129	4,992	4,196	3,611
Proved Undeveloped	76,246	54,834	40,555	30,507	23,127
Total Proved	**146,634**	**113,356**	**90,818**	**74,737**	**62,772**
Probable	115,749	72,944	49,652	35,686	26,642
Total Proved Plus Probable	**262,383**	**186,300**	**140,470**	**110,423**	**89,414**

Future Development Costs

The following table sets forth elements of future net revenue attributed to Proved Reserves and Proved Plus Probable Reserves of the Corporation as of December 31, 2012, based on forecast price assumptions and calculated without discount.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2012

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Investment Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Future Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved Developed Producing	115,848	16,120	27,948	3,050	6,192	62,538	-	62,538
Proved Developed Non-Producing	17,933	2,632	5,874	1,579	-	7,849	-	7,849
Proved Undeveloped	228,287	30,862	46,325	56,250	1,664	93,186	16,940	76,246
Total Proved	**362,068**	**49,613**	**80,147**	**60,878**	**7,856**	**163,573**	**16,940**	**146,634**
Probable	308,819	51,865	70,925	30,057	1,753	154,123	38,374	115,749
Proved Plus Probable	**670,886**	**101,478**	**151,072**	**90,935**	**9,610**	**317,696**	**55,314**	**262,383**

The following table sets forth the net present value of future net revenues by production group attributed to Prove and Proved plus Probable Reserves of the Corporation as of December 31, 2012, based on forecast price assumptions.

NET PRESENT VALUES OF FUTURE NET REVENUE
BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2011

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Net Reserves Unit Value Before Income Taxes (Discounted at 10%/Year) ($/bbl)
Proved	Light and Medium Oil (including solution gas and by-products)	58,455.5	$ 22.71
	Associated and Non-Associated Gas (including by-products)	41,192.2	$ 11.38
	TOTAL	**99,649.8**	$ 22.69
Proved Plus Probable	Light and Medium Oil (including solution gas and by-products)	96,869.4	$ 21.93
	Associated and Non-Associated Gas (including by-products)	70,511.7	$11.28
	TOTAL	**167,381.0**	$ 15.69

Definitions

"**Working Interest Gross**" reserves are the Company's working interest (operating or non-operating) share before deducting royalty obligations and without including any royalty interests of the Company.
"**Company Share Gross**" reserves are the Company's working interest (operating or non-operating) share and before deducting royalty obligations but including any royalty interests of the Company.
"**Net**" reserves are the Company's working interest (operating or non-operating) share after deduction of royalty obligations plus any royalty interests of the Company.
"**Reserves**" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according with the level of certainty associated with the estimates and may be sub-classified based on development and production status.
"**Production**" is the cumulative quantity of petroleum that has been recovered at a given date.
"**Proved Reserves**" are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves is the targeted level of certainty.
"**Probable Reserves**" are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves. At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probably reserves is the targeted level of certainty.
"**Developed Reserves**" are those Reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the Reserves on production. The developed category may be subdivided into producing and non-producing.
"**Developed Producing Reserves**" are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
"**Developed Non-Producing Reserves**" are those Reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
"**Undeveloped Reserves**" are those Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the Reserves classification (proved, probable) to which they are assigned.

Pricing Assumptions

Forecast Prices Used in Estimates

The forecast price and market forecasts prepared by Deloitte are based on information available from numerous government agencies, industry publication, oil refineries, natural gas marketers, and industry trends. The prices are Deloitte's best estimate of how the future will look, based on the many uncertainties that exist in both the domestic Canadian and international petroleum industries. Deloitte considers the current monthly trends, the actual and trends for the year to date, and the prior year actual in determining the forecast. The crude oil and natural gas forecasts are based on yearly variable factors weighted to higher percent in current data and reflecting a higher percent to the prior year historical. These forecasts are Deloitte's interpretation of current available information and while they are considered reasonable, changing market conditions or additional information may require alteration from the indicated effective date.

Inflation forecasts and exchange rates, an integral part of the forecast, have also been considered.

	Price Inflation Rate	Cost Inflation Rate	Cdn to US Exchange Rate
2012	1.6%	1.6%	$1.000
2013	0.0%	0.0%	$1.000
2014	2.0%	2.0%	$1.000
2015	2.0%	2.0%	$1.000
2016	2.0%	2.0%	$1.000
2017 beyond	2.0%	2.0%	$1.000

Oil, NGL, and natural gas base case prices, utilized by Deloitte in the Deloitte Reserve Report were as follows:

Price Forecast Used in Estimates

	Oil			Natural Gas			Natural Gas Liquids		
Year	WTI Cushing (Oklahoma)	Edmonton City Gate 40° API	Bow River 25° API Hardisty	Alberta AECO – Gas Prices	Alberta Direct Plant Gate Sales	Alberta System Plant Gate Sales	Pentanes + Condensate Edmonton	Butanes Edmonton	Propane Edmonton
	($US/bbl)	($Cdn/bbl)	($Cnd/bbl)	($Cdn/mcf)	($Cdn/mcf)	($Cdn/Mcf)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)
Historical									
2005	$56.61	$69.33	$45.68	$8.78	$8.61	$8.61	$74.67	$51.91	$43.23
2006	$66.06	$73.34	$52.04	$6.54	$6.35	$6.35	$78.19	$58.16	$44.11
2007	$72.38	$77.09	$53.86	$6.44	$6.22	$6.22	$81.67	$59.40	$49.77
2008	$99.58	$102.83	$83.97	$8.15	$7.92	$7.92	$109.80	$83.56	$56.94
2009	$61.78	$66.21	$59.90	$3.96	$3.74	$3.74	$69.59	$56.29	$34.56
2010	$79.42	$77.79	$68.16	$4.00	$3.76	$3.76	$84.68	$69.02	$45.60
2011	$94.99	$95.77	$78.60	$3.65	$3.46	$3.46	$104.70	$83.62	$53.34
2012	$94.00	$87.76	$75.47	$2.40	$2.20	$2.62	$98.74	$75.21	$33.71
Forecast									
2013	$90.00	$85.00	$67.00	$3.20	$3.00	$2.90	$89.25	$72.25	$46.75
2014	$89.75	$84.70	$66.70	$3.70	$3.55	$3.45	$88.95	$72.00	$46.60
2015	$91.55	$89.45	$70.45	$3.90	$3.85	$3.75	$93.90	$76.05	$49.20
2016	$93.40	$91.20	$71.20	$4.10	$4.15	$4.05	$95.75	$77.50	$50.15
2017	$92.00	$89.80	$70.80	$4.30	$4.45	$4.35	$94.30	$76.35	$49.40
2018	$93.85	$91.60	$71.60	$4.60	$4.90	$4.80	$96.20	$77.85	$50.40

Notes:

- All prices are in Canadian dollars except WTI and NYMEX which are in U.S. dollars.
- Edmonton City Gate prices based on light sweet crude posted at major Canadian refineries (40 Deg. API <0.5% Sulphur).
- Natural Gas Liquid prices are forecasted at Edmonton therefore an additional transportation cost must be included to plant gate sales point.
- 1 Mcf is equivalent to 1 mmbtu.
- System gas prices include TCGSL, Progas, Pan Alberta and Alliance.
- Alberta gas prices, except AECO, include an average cost of service to the plant gate.
- Real dollars listed include future growth in prices with no escalation considered.

Weighted average historical prices realized by Yangarra for the year ended December 31, 2012 before transportation were $2.49/Mcf for natural gas, $46.78/Bbl for NGLs and $84.09/Bbl for oil.

Reconciliations of Changes in Reserves

The following table sets out a reconciliation of the changes in the Corporation's reserves as at December 31, 2012 against such reserves at December 31, 2011 based on forecast prices and cost assumptions:

	Light and Medium Oil			**Natural Gas Liquids**			**Associated & Non-Associated Gas**		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
	(Mstb)	(Mstb)	(Mstb)	(Mstb)	(Mstb)	(Mstb)	(MMcf)	(MMcf)	(MMcf)
Opening Balance	**1,404.6**	**798.4**	**2,202.9**	**532.6**	**333.3**	**865.9**	**17,403.1**	**11,256.8**	**28,659.9**
Production	-113.9	0.0	-113.9	-126.5	0.0	-126.5	-2,116.6	0.0	-2,116.6
Technical Revisions	-374.3	-72.6	-446.8	407.9	203.2	611.1	665.9	2,020.8	2,686.7
Extensions & Improved Recovery	1,045.9	735.3	1,781.1	290.8	253.5	544.2	4,534.9	3,447.4	7,982.3
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	-1.9	1.2	-0.7	-1.6	-0.3	-1.9	-193.0	-112.9	-305.9
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0	612.3	227.4	839.7
Closing Balance	**1,960.3**	**1,462.3**	**3,422.6**	**1,103.1**	**789.6**	**1,892.7**	**20,906.6**	**16,839.5**	**37,746.1**

Timing of Initial Undeveloped Reserves Assignment

The following table sets forth the gross volumes of proved undeveloped reserves, by each product type, attributed to the Corporation's assets for the years ended December 2012, 2011, and 2010, based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbl)
2010	304.9	3,260.5	133.3
2011	535.4	8,965.1	236.0
2012	1,306.3	12,369.9	670.7

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in for production or wells not yet drilled at year end that are adjacent to producing wells. In addition, such reserves may relate to planned infill drilling locations. Plans are included in the Deloitte report to develop these reserves. The future timing of these undeveloped reserves reflects an orderly operational development of the reserves considering infrastructure limitations and corporate portfolio management.

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbl)
2010	407.4	3,470.0	139.7
2011	668.5	10,590.7	265.4
2012	2,486.0	22,665.4	1,269.6

Significant Factors or Uncertainties Affecting Reserves Data

Probable undeveloped reserves are generally adjacent to proven undeveloped reserves, lands contiguous to production or indicated by analogy to be productive. In general, once proved and/or probable undeveloped reserves are identified, Yangarra schedules them into development plans within two years.

A number of factors that could result in delayed or cancelled development are: changing economic conditions (due to pricing, operating and capital expenditure fluctuations); changing technical conditions (for example production anomalies such as water breakthrough or accelerated depletion); multi-zone developments (for example, 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.

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and cost changes. The Corporation's estimates are based on current production forecast, prices and economic conditions.

As additional data and circumstances change, reserve estimates also change. Based on new information, reserves estimates are reviewed and revised, either downward or upward as warranted. As new geological, production and economic data is incorporated into the process of estimated reserves the accuracy of the reserve estimate improves.

The Corporation's reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Corporation's control.

The Corporation's oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company which have been disclosed in financial statements and management's discussion and analysis as filed on SEDAR (www.sedar.com) and this Annual Information Form.

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:

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) ($M)
2013	46,026.8	60,244.6
2014	12,331.3	23,699.8
2015	655.5	832.3
2016	689.8	742.8
2017	297.7	3,918.4
Thereafter	877.0	1,497.4
Total for all years undiscounted	60,878.1	90,935.3

Yangarra expects that such funding of its share of future development on capital expenditure programs will be primarily obtained from internally generated cash flow and debt financing.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest or a royalty interest as at December 31, 2012, which are producing or which the Corporation considers to be capable of production. All wells set forth in the table are located in Alberta.

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Medicine Hat, Alberta				
Producing	-	-	-	-
Shut-in	-	-	81	81.0
Central Alberta				
Producing	24	12.73	20	11.82
Shut-in	5	0.82	4	1.65
Jaslan, Alberta				
Producing	-	-	-	-
Shut-in	-	-	11	11.0

Notes:

(1) Shut-in wells means wells which are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons.

(2) Gross wells are defined as the total number of wells in which the Corporation has an interest.

(3) Net wells are defined as the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.

Property Overview

The following is a description of the major oil and natural gas properties, and facilities in which the Corporation had an interest as of December 31, 2012. Production volumes represent the working interest share of the Corporation before the deduction of royalties. Reserve amounts are stated, before deduction of royalties, at December 31, 2012 based on escalating cost and price assumptions, as set forth in the 2012 Reserves Report.

Central Alberta Area

Yangarra holds working interests ranging from 24.375% to 100% in multiple sections in this area with high potential Glauconitic (45 gross (24.0 net) sections), Cardium (27 gross (15.5 net) sections), Viking, Second White Specs (45 gross (29.0 net) sections), Rock Creek and Ellerslie zones. The field is located 60 miles north west of Red Deer, near the town of Rocky Mountain House, Alberta. Yangarra has a 50% ownership in a compressor station in the Willesden Green area of Central Alberta capable of 10 Mmcf/d constructed in early 2004. Yangarra constructed another compressor facility in the Ferrier area of Central Alberta early in 2013; this compressor station capable of 12 Mmcf/d. Both facilities process third party volumes providing the Corporation with incremental profit. Yangarra has a 100% interest in a field office with accommodation, a shop and storage. There is an overriding sliding scale royalty (5-15%) covering approximately 11 sections in this area that was purchased by the Corporation in 2010. As of December 31, 2012 44 gross wells (24.6 net wells) are producing and 9 gross (2.5 net) wells are shut-in.

Medicine Hat Area

Yangarra holds a 100% working interest in a total of 75 sections of land located 25 miles southwest of the city of Medicine Hat, Alberta. A total of 81 wells have been drilled, re-entered, or acquired on the property. A 100% owned compressor station, capable of 2 million cubic feet per day situated at 5-25-9-6W4 was built at the end of 2003. Production is from the Sunburst, Bow Island, Second White Specks, Medicine Hat, and Milk River Formations. Plans for Medicine Hat area are suspended until gas prices rebound. Wells, assigned reserves that are drilled and capable of producing, have not been tied in, will be tied in as development of the field reaches these outlying wells or prices increase. As at December 31, 2012 all wells in the Medicine Hat area were shut-in due to low natural gas prices.

Jaslan Area

The Jaslan property is located 100 miles north east of Edmonton and consists of 17.25 sections (100% working interest) in the north block and south block. A compressor station capable of 3.0 million cubic feet per day (100% working interest) and gathering system were completed in November 2006. Currently all wells in the Jaslan area are shut-in due to low natural gas prices. During 2011, Yangarra purchased their partners interest in the Jaslan area to increase its working interest to 100%.

Properties with No Attributed Reserves

The following table sets out the Corporation's undeveloped land holdings as of December 31, 2012.

Location	Gross (hectares)	Net (hectares)
Alberta	44,051	40,715

At December 31, 2012, there was no material commitments associated with the Corporation's undeveloped land holdings. The Corporation expects that rights to explore, develop, and exploit 17,760 net hectares of undeveloped land holdings will expire within one year, but intends to drill or submit applications to continue selected portions of the above acreage.

Significant Factors to Properties with No Attributed Reserves

The Corporation expects to develop the unrecognized natural gas assets in Jaslan and Medicine Hat as natural gas prices improve.

Forward Contracts

As at December 31, 2012, the Corporation was committed to the following commodity price risk contracts for the sale of oil:

2013 Contracts:

- 200 bbl/d from January 1 to December 31, 2013 at a fixed price of $98.00 CAD/bbl;
- 100 bbl/d from January 1 to December 31, 2013 at a fixed price of $97.50 CAD/bbl;
- 200 bbl/d from January 1 to December 31, 2013 at a fixed price of $98.30 USD/bbl;
- 100 bbl/d from January 1 to December 31, 2013 at a fixed price of $98.00 USD/bbl;
- 100 bbl/d from January 1 to December 31, 2013 at a fixed price of $104.80 CAD/bbl and;
- Sold calls on 200 bbl/d d from January 1 to December 31, 2013 at $110 USD/bbl.

2014 Contracts:

- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $98.30 CAD/bbl;
- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $100.00 CAD/bbl;
- 100 bbl/d from January 1 to December 31, 2014 at a fixed price of $101.05 CAD/bbl; and
- Sold Swaption on 200 bbl/d @ $100.00 WTI/USD for January – December 2014.

As at December 31, 2012, the Corporation was committed to the following commodity price risk contracts on the AECO basis:

- 2,000 GJ/d at $3.51/GJ for January – December 2013;
- 1,000 GJ/d at $3.35/GJ for January – December 2013; and
- 500 GJ/d at $3.42/GJ for January – December 2013.

Exploration and Development

In 2013, the Corporation intends to undertake a portfolio of exploration and development projects to capture and advance projects that provide opportunities utilizing multi-well pads and horizontal drilling with multi-stage fracturing technology. The Corporation's 2013 capital program is anticipated to be equivalent to operating cash flows.

Additional Information Concerning Abandonment and Reclamation Costs

The 2012 Reserves Report includes well abandonment costs ranging at rates of $33,000-$50,000 per well. The abandonment costs are based on area averages taken from the Energy Resource Conservation Board ("ERCB") Directive 011 called the "Alberta Regional Well Abandonment Cost Tables". The 2012 Reserves Report does not address well site reclamation for existing wells, pipeline right-of-ways, and facility abandonment/salvage costs including potential environmental concerns.

Yangarra has 145 gross wells for which it expects to incur abandonment and restoration costs. These costs included well abandonment and surface lease reclamation. The estimated total abandonment and reclamation costs, forecast net of estimated salvage value, under the proved reserves category is $7,856.2 M (undiscounted), and $3,432.80M (discounted at 10%). The total proved plus probable abandonment and reclamation costs are $9,609.5 M (undiscounted), and $3,143.81M (discounted at 10%). 100% of such amounts were deducted as abandonment costs in estimating future net revenue of the Corporation in respect of proved and proved plus probable reserves as disclosed above. Estimated abandonment costs are included in the 2012 Reserves Report as a deduction in arriving at future net revenue.

Forecast Prices and Costs – Proved (M$)

Year	Abandonment Costs (Undiscounted)	Abandonment Costs (Discounted at 10%)
2013	0.0	0.0
2014	262.0	226.4
2015	460.9	362.0
2016	487.1	349.0
2017	496.8	323.6
Thereafter	6,149.3	2,171.8
Total	7,856.2	3,432.8

Forecast Prices and Costs – Proved Plus Probable (M$)

Year	Abandonment Costs (Undiscounted)	Abandonment Costs (Discounted at 10%)
2013	0.0	0.0
2014	206.1	178.0
2015	305.9	240.2
2016	481.8	345.2
2017	634.3	413.2
Thereafter	7,981.4	1,967.2
Total	9,609.5	3,143.8

Tax Horizon

Yangarra was not required to pay income tax in 2012 and based on current tax pools, projected cash flow, and projected exploration costs, the Corporation does not expect to be taxable in 2013.

Costs Incurred

In 2012, exploration and development capital expenditures were $24 million. The breakdown for the Corporation's capital expenditures during 2012 is presented below:

	($000's)
Drilling and Completions	$ 19,728
Facilities	2,812
Geological and Geophysical	1,002
Land Lease	735
Total	$ 24,277

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Yangarra participated during the year ended December 31, 2012.

Exploration Wells	Gross	Net	**Development Wells**	Gross	Net
Light and Medium Oil	-	-	Light and Medium Oil	6	3.8
Natural Gas	-	-	Natural Gas	1	1.0
Service	-	-	Service	-	-
Dry		-	Dry	-	-
Total	-	-	Total	7	4

Production Estimates

The following table sets out the volume of Yangarra's production estimated for the first year reflected in the estimates of future gross revenue disclosed in the tables contained under "Disclosure of Reserves Data".

	Total Proved Reserves			Total Proved + Probable Reserves		
	Light and medium oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Light and medium oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)
Medicine Hat	-	119.7	-	-	123.0	-
Central Alberta	875.3	8,734.5	526.6	1,065.0	9,748.8	597.5
Jaslan	-	145.8	-	-	169.9	-

* Table includes fields that account for more than 20% of the estimated production reflected in the estimate of future net reserves.

Production History

The following tables set forth the Corporation's average daily production volume before deductions of royalties payable to others, and crude oil, NGLs and natural gas prices. Also shown are royalties, production and transportation costs, and average netbacks for the period January – December 2012.

Average Daily Production

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil (bbl/d)	438.3	269.4	272.7	418.3
Natural gas (mcf/d)	6,017.5	6,114.6	5,616.6	4,607.3
Natural gas liquids (bbl/d)	347.2	397.2	316.7	304.2
Royalty Income (bbl/d)	350.4	335.9	274.0	209.4
Total (BOE/d)	2,138.9	2,021.5	1,799.6	1,699.7

Average Prices Received per Unit – (Before Deduction of Royalties)

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil ($/bbl)	90.95	81.97	79.31	77.78
Natural gas ($/mcf)	2.09	2.05	2.01	2.94
Natural gas liquids ($/bbl)	64.96	55.22	38.62	18.27
BOE ($ / BOE)	37.61	33.35	31.47	35.78

Royalties Paid per Unit

Three months ended	March 31	June 30	Sept 30	Dec 31
Total royalties per BOE ($/BOE)	2.30	1.54	1.96	0.02

Production and Transportation Costs

Three months ended	March 31	June 30	Sept 30	Dec 31
Total costs per BOE ($/BOE)	5.65	8.00	6.81	10.60

Netbacks Received

Three months ended	March 31	June 30	Sept 30	Dec 31
Total netbacks per $/BOE	29.67	23.81	22.70	25.16

Production Volume by Field

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2012:

	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Royalty Income (Bbls/d)	BOE (BOE/d)
Medicine Hat	-	-	-		-
Central Alberta	350	5,586	341	292.1	1,914
Jaslan	-	-	-	-	-

Uncertainty of Reserves Estimates

The reserve and recovery information contained in the 2012 Reserves Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the independent estimates of Deloitte.

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Corporation. The reserve and cash flow information set forth herein represent estimates only. The reserves and estimated future net cash flow from the Corporation's assets have been independently evaluated effective December 31, 2012 by Deloitte. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success in the evaluations.

DIRECTORS AND OFFICERS OF THE CORPORATION

The name, province and country of residence and principal occupation for the last five years of each of the directors and executive officers of the Corporation are as follows:

Name and Municipality of Residence	Office	Principal Occupation	Director Since	Common Shares Held
James G. Evaskevich[3][4] Alberta, Canada	President, Chief Executive Officer, and Director	President and Chief Executive Officer of the Corporation since December 2001.	December 19, 2001	6,453,560 (5.30%)[5]
James Glessing Alberta, Canada	Chief Financial Officer	Chief Financial Officer of the Corporation since December 1, 2010. Prior thereto CFO & VP Finance 2007-2010, and Controller (2005-2007) at BlackRock Ventures.	N/A	562,500 (0.46%)[6]
Michael d'Entremont Alberta, Canada	Chief Operating Officer	Chief Operating Officer of the Corporation since March 12, 2012. Prior thereto consultant at Charlton Capital Corp (2010-2012) and President and CEO for Livingston Energy (2003-2009).	N/A	30,000 (0.02%)
Ronald Gardiner Alberta, Canada	Vice President, Exploration	VP Exploration of the Corporation since January 28, 2010. Prior thereto, VP Exploration at Keeper Resources from 2004.	N/A	400,500 (0.33%)
Randall Faminow Alberta, Canada	Vice President, Land	VP Land of the Corporation since October 18, 2011. Prior thereto VP, Land for Spry Energy Ltd (2007-2011), and VP, Land at Great Plains Exploration Inc (2003-2006)	N/A	358,500 (0.29%)
Lorne Simpson Alberta, Canada	Vice President, Operations	VP Operations of the Corporation since April 11, 2013. Prior thereto Manager of Drilling and Completions for the Corporation (2012-2013), Supervisor, Drilling Operations with PetroBakken Energy Ltd. (2010-2012), Manager Drilling and Completions with Open Range (2009-2010).	N/A	999,000 (0.82%)
Gordon A. Bowerman[1][2][3][4] Alberta, Canada	Director	President of Cove Resources Ltd., a private oil and gas company based in Calgary, since 1987.	December 19, 2001	10,343,972 (8.50%)[7]
Robert D. Weir[1][2][3][4] Alberta, Canada	Director	President of Weir Resource Management Ltd., a private company based in Calgary, since 1981.	November 11, 2003	854,455 (0.70%)[8]
Joseph S. Durante[1][2][3][4] Alberta, Canada	Director	Managing Director of Toscana Capital Corporation since January, 2003.	January 7, 2010	Nil [10]
W.W. (Chuck) Charlton [1][2][3][4] Alberta, Canada	Director	President of Charlton Capital Corporation since 2003.	August 20, 2012	1,402,609 (1.15%)[9]

Notes:

(1) Member of the Audit Committee of the Board of Directors.

(2) Member of the Reserves Committee of the Board of Directors.

(3) Member of the Health and Safety Committee of the Board of Directors.

(4) Member of the Nominating, Compensation and Corporate Governance Committee of the Board of Directors.

(5) Includes 2,811,213 Common Shares held by Grassy Island Ranch Ltd., a private company controlled by Mr. Evaskevich.

(6) Includes 8,900 Common Shares held by Mr. Glessing's spouse.

(7) Includes 797,163 Common Shares held by Mr. Bowerman's spouse, over which Mr. Bowerman has control and direction over and 1,679,070 Common Shares held by Cove Resources Ltd., a private company controlled by Mr. Bowerman.

(8) Includes 4,166 Common Shares held by Weir Resources Management Ltd. and 3,800 Common Shares held by Wild Bull Resources, both private companies controlled by Mr. Weir.

(9) Includes 999,700 held by Char Holdings Ltd., a private company controlled by Mr. Charlton

(10) Mr. Durante is a Managing Director of Toscana Capital Corporation, whose affiliate, Toscana LP, holds 1,734,164 Common Shares.

Orders

To the knowledge of management of the Corporation, other than as disclosed herein, no director or executive officer as at the date hereof, or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any company (including the Corporation), that (a) was subject to 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. For the purposes hereof, "order" means (a) a cease trade order, (b) an order similar to a cease trade order, or (c) an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

Bankruptcies

Other than as disclosed below, no director or executive officer of the Corporation is, as of the date hereof, or has been, within 10 years before the date hereof, a director or executive officer of any company that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal to 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.

On October 7, 2009 the Corporation filed a proposal with its creditors to restructure under Part III Division I of the *Bankruptcy and Insolvency Act* (Canada), including a plan to merge with Athabaska Energy Ltd. See "Interest of Informed Persons in Materials Transactions" below. At the time of the Restructure Proposal, the directors and officers of Yangarra consisted of James Evaskevich, Gordon Bowerman, Robert Weir, Arthur Dumont, Penny Payne, and Dan Helman.

No director or executive officer of the Corporation has, within 10 years before the date hereof, 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 its assets.

Penalties and Sanctions

To the knowledge of management of the Corporation, no director or executive officer or shareholder holding a sufficient number of common shares to affect materially the control of the Corporation, has been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority, or has been subject to any other penalties or sanctions imposed by a court or regulatory body that would be likely to be considered important to a reasonable investor 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 to in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial or director positions with other oil and natural 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. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Certain of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation.

AUDIT COMMITTEE

The purpose of the Corporation's audit committee is to provide assistance to the Board of Directors (the "**Board**") in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Corporation. It is the objective of the audit committee to maintain a free and open means of communications among the Board, the independent auditors and the senior management of the Corporation.

The full text of the audit committee's charter is attached hereto as Schedule "C" and forms part of this Annual Information Form.

Composition of the Audit Committee

The audit committee is comprised of Gordon Bowerman (Chair), Robert Weir, Joseph Durante and W.W. (Chuck) Charlton. Each of the members are independent within the meaning of section 1.4 of National Instrument 52-110 *Audit Committees* ("**NI 52-110**"). Each of the members is financially literate within the meaning of section 1.6 of NI 52-110.

Relevant Education and Experience

The following relevant education and experience of the members of the Audit Committee have been used in assessing their financial literacy:

Gordon Bowerman, B.A. – Mr. Bowerman has over 40 years experience in the oil and gas industry, including various experience in production, land, accounting, asset purchases and sales. Mr. Bowerman currently is the President of a private oil and gas company.

Robert Weir, P. Eng – Mr. Weir has over 30 years experience in the oil and gas industry, President of Weir Resource Management Ltd., a private company based in Calgary, since 1981.

Joseph Durante – Mr. Durante has over 30 years experience in the financial industry, including with various public companies in the oil and gas sector.

W.W. (Chuck) Charlton – Mr. Charlton has over 35 years experience in the financial industry, President of Charlton Capital Corp, a private investment banking company based in Calgary, since 2003.

Pre-Approval Policies and Procedures

The audit committee pre-approves engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence.

Audit Committee Oversight

At no time since the commencement of the Corporation's most recently completed financial year was a recommendation of the Committee to nominate or compensate an external auditor (currently, KPMG LLP, Chartered Accountants) not adopted by the Board.

Reliance on Certain Exemptions

Since the effective date of NI 52-110, the Corporation has not relied on the exemptions contained in sections 2.4 or 8 of NI 52-110. Section 2.4 provides an exemption from the requirement that the audit committee must pre-approve all non-audit services to be provided by the auditor, where the total amount of fees related to the non-audit services are not expected to exceed 5% of the total fees payable to the auditor in the fiscal year in which the non-audit services were provided. Section 8 permits a company to apply to a securities regulatory authority for an exemption from the requirements of NI 52-110, in whole or in part.

The Corporation is also relying on the exemption set out in section 6.1 of NI 52-110 with respect to compliance with the requirements of Part 5 (Reporting Obligations) of NI 52-110.

External Auditor Service Fees (By Category)

Year Ended	Audit Fees	Audit Related Fees	Tax Fees	All Other Fees
December 31, 2012	$39,000	$37,500	$875	$2,625(1)
December 31, 2011	$65,000	$83,840	-	$5,309(1)

Note:

(1) Represents administration fees of the Auditor

DESCRIPTION OF SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of Common Shares, without nominal or par value, and an unlimited number of First Preferred Shares (the "**First Preferred Shares**") and the Second Preferred Shares in the capital of the Corporation, both issuable in series (the "**Second Preferred Shares**", and together with the First Preferred Shares, the "**Preferred Shares**"). As of the date of this Annual Information Form, 121,711,722 Common Shares and nil Preferred Shares are issued and outstanding.

Common Shares

Holders of post-consolidation Common Shares are entitled to (a) one vote per post-consolidated Common Share at all meetings of shareholders of the Corporation; (b) receive dividends if, as and when declared by the Board, as a class equally with the holders of the Preferred Shares, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the post-consolidation Common Shares in respect of dividends; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the post-consolidation Common Shares in respect of return of capital on dissolution, share rateably, together with the holders of Preferred Shares and of shares of any other class of shares of the Corporation ranking equally with the post-consolidation Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

First Preferred Shares

Holders of First Preferred Shares shall: (a) not be entitled to receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) be entitled to receive dividends if, as and when declared by the Board on the First Preferred Shares as a class in preference to the holders of the Second Preferred Shares and post-consolidation Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends; and (c) be entitled to, in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive in preference to the holders of the Second Preferred Shares and post-Consolidation Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

Series A First Preferred Shares

The Corporation previously had a series of First Preferred Shares outstanding ("**Series A First Preferred Shares**") Holders of Series A First Preferred Shares shall: (a) not be entitled to receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) be entitled to receive dividends: (i) on a semi-annual basis within 30 days of the first and second fiscal-year halves of the Corporation, which can be paid in the form of cash or post-consolidation Common Shares at the election of the Board, with the deemed price of such post-consolidation Common Shares to be the Market Price (as such term is defined in the Corporate Finance Manual of the TSX Venture Exchange) of such post-consolidation Common Shares at the time of settlement on the First Preferred Shares; (ii) as a class in preference to the holders of the Second Preferred Shares and post-consolidation Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends; and (iii) each Series A First Preferred Share shall be entitled to a cumulative dividend at the rate of 5% per annum on the stated amount of $1.00 per Series A Preferred Share (the "**Stated Amount**") of such Series A First Preferred Share; (c) be entitled to, in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive an amount equal to the Stated Amount per Series A First Preferred Share plus any declared but unpaid dividends prior to any payment or distribution to any other class of shares of the Corporation; and (d) have the option, exercisable not earlier than the date that is 18 months after the Series A Preferred Shares are issued, to force the Corporation to redeem or purchase all or any of the Series A First Preferred Shares held by such holder. In addition, the Corporation has the right to redeem the Series A First Preferred Shares at any time in cash at the price equal to the Stated Amount plus any declared but unpaid dividends.

Second Preferred Shares

Holders of Second Preferred Shares shall not be entitled to (a) receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) receive dividends if, as and when declared by the Board on the First Preferred Shares as a class in preference to the holders of the post-consolidation Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the Second Preferred Shares in respect of dividends; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive in preference to the holders of the post-consolidation Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the Second Preferred Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

DIVIDENDS

The Corporation has not declared or paid any dividends on the Common Shares. Any decision to pay dividends on such shares in the future will be made by its Board on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time. It is not the current intention of the Corporation to pay any dividends on the post-consolidation Common Shares in the near future.

As of this date, Yangarra has paid $59,247 in cash dividends on the then outstanding Series A First Preferred Shares. See "Description of Share Capital – First Preferred Shares – Series A First Preferred Shares". On March 8, 2011, the Corporation redeemed all outstanding Series A First Preferred Shares for $1,000,000 cash plus then outstanding dividends payable.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares have been listed and posted for trading on the TSX Venture Exchange since July 25, 2003 under the trading symbol "YAN" and changed as a result of the Consolidation on April 30, 2010 and began trading under the symbol "YGR". The following table sets out the price range for, and trading volume of, the post-consolidation Common Shares as reported by the TSX Venture Exchange for the periods indicated:

	Trading Price		Volume Traded
	High	Low	# of shares
January 2011	$0.87	$0.75	1,741,700
February 2011	$0.81	$0.73	3,294,900
March 2011	$0.77	$0.68	6,205,400
April 2011	$0.72	$0.63	2,167,800
May 2011	$0.70	$0.64	1,971,300
June 2011	$0.70	$0.61	3,440,400
July 2011	$0.80	$0.65	1,445,900
August 2011	$0.75	$0.61	1,638,800
September 2011	$0.65	$0.52	7,854,900
October 2011	$0.66	$0.53	5,783,800
November 2011	$0.67	$0.57	1,347,200
December 2011	$0.63	$0.57	656,800
January 2012	$0.64	$0.47	1,618,200
February 2012	$0.55	$0.43	2,967,500
March 2012	$0.55	$0.41	2,346,900
April 2012	$0.48	$0.34	5,211,700
May 2012	$0.41	$0.32	1,065,900
June 2012	$0.37	$0.23	4,026,800
July 2012	$0.35	$0.30	658,200
August 2012	$0.39	$0.30	715,000
September 2012	$0.37	$0.31	1,339,100
October 2012	$0.37	$0.31	1,748,000
November 2012	$0.42	$0.32	4,506,000
December 2012	$0.38	$0.29	1,323,600

ESCROWED SECURITIES

No securities of the Corporation are currently escrowed.

INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

Companies operating in the oil and natural gas industry are subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and natural gas industry. It is not expected that any of such controls or regulations would affect the operations of the Corporation in a manner materially different than they would affect other companies of similar size in the oil and natural 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.

Pricing and Marketing

Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with a competitive open market setting the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board (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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

In Canada, the price of natural gas results from transactions between buyers and sellers in an open, transparent market environment. 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 export contracts in excess of two years must continue to meet certain criteria prescribed by the NEB and the government of Canada. As is the case with oil, natural gas exports for a term of less than two years must be made pursuant to an NEB order, or, in the case of exports for a longer duration, pursuant to an NEB licence and Governor in Council approval. The price received by the Corporation depends, in part, on the prices of competing natural gas and other substitute fuels, access to downstream transportation, distance to markets, length of the contract term, weather conditions, the supply and demand balance and other contractual terms.

The governments of Alberta also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as availability of reserves, transportation arrangements and market considerations.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the U.S. and Mexico became effective. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed provided that the restrictions are justified under certain provisions of the General Agreement on Tariffs and Trade then only if the export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of the energy resource (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, to minimize disruption of contractual arrangements and to avoid undue influence with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, NGLs, 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, from time to time, carved out of the working interest owner's interest 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 make annual rental payments, currently at a rate of $3.50 per hectare, and monthly royalty payments in respect of oil and natural gas produced.

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act*, 2008. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system that were intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors; specifically, the maximum royalty rates for conventional oil and natural gas production will be decreased effective for the January 2011 production month and certain temporary incentive programs currently in place will be made permanent. Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure, which classified oil based on the date of discovery of the pool. Under the NRF, 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. Royalty rates for conventional oil under the NRF range from 0% to 50%, an increase from the previous maximum rates of 30% to 35% depending on the vintage of the oil, and rate caps are set at $120/bbl. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 40%.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF range from 5% to 50%, an increase from the previous maximum rates of 5% to 35%, and rate caps are set at $17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 36%.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a $200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the Corporation's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 bbls of oil or 500 Mmcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

Land Tenure

Crude oil and natural gas located in the western Canadian provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms from two years and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

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

In Alberta, the NRF includes a policy of "shallow rights reversion", which provides, for the first time in western Canada, for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licences. For leases and licences issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or licence. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licences receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

Companies operating in the oil and natural gas industry are subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines or issuance of clean-up orders. Under the *Environmental Protection and Enhancement Act* (Alberta), changes in these regulations have had an incremental effect on the cost of conducting operations in Alberta.

The Corporation is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature, as a result of the increasingly stringent laws relating to the protection of the environment. The Corporation's internal procedures are designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding. The Corporation believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol (the "**Kyoto Protocol**"), which requires a reduction in greenhouse gas emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its greenhouse gas emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark from December 6 to 18, 2009 (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing greenhouse gas emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding greenhouse gas emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

In response to the Copenhagen Accord, the Government of Canada has recently indicated that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous federal government policy documents which are discussed below.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change". It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

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 greenhouse gases 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**"). Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have recently indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. The approach of the Unites States is expected to include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan.

In the absence of United States federal climate legislation permitting a cap and trade program in the United States, the Environmental Protection Agency (the "**EPA**") is proposing a number of standards-based regulatory initiatives to regulate greenhouse gas emissions, including the regulation of greenhouse gas emissions from large stationary sources. The EPA promulgated the Mandatory Reporting of Greenhouse Gases Rule (the "**Rule**") on December 29, 2009, which rule requires reporting from large sources and suppliers. The EPA is proposing to add new sources by way of amendments to the Rule that will include petroleum and natural gas facilities emitting 25,000 metric tonnes or more of CO_2 equivalents per year.

As a result of the foregoing, many provisions of the Updated Action Plan, as described below, are expected to be significantly modified. The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions to 20% below 2006 levels by 2020 and 60% to 70% below 2006 levels by 2050. As noted above, the goal has now been modified by the Government of Canada. The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets will be applied to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010, followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity or (ii) involve significant changes to the processes of the facility. New Facilities will be given a three-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors govern by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010-12 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol, which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

The Updated Action Plan may be significantly changed if, as a result of the Canada/U.S. Clean Energy Dialogue, Canada adopts targets and regulatory tools similar to those adopted in the United States in order to regulate the emission of greenhouse gases.

Under section 46(1) of the *Canadian Environmental Protection Act, 1999*, the Government of Canada requires mandatory reporting of greenhouse gas emissions. Notices are published in the *Canada Gazette* setting out the greenhouse gases, their respective global warming potential and the criteria for reporting. The "*Canada Gazette* Notice for 2009 Emissions" sets out the requirement for facilities that exceed the 50,000-metric-tonne CO_2-equivalent greenhouse gas threshold to report their annual emissions on or before June 1, 2010.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on July l, 2007, amending it 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 similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of greenhouse gases per year must comply with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed eight or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12% from a baseline established by their average emissions intensity between 2003 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gus Emitters Regulation*. New Facilities are also required to reduce their emissions intensity by 12%, but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first three years of operation of the New Facility. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

The CCEMA contains compliance mechanisms similar to those in the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can 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. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

RISK FACTORS

The holding of securities in the Corporation should be considered highly speculative due to the nature of the Corporation's business and the present stage of its development. The following is a summary of certain risk factors relating to the activities of the Corporation and the ownership of the Corporation's securities which should be carefully considered before making an investment decision relating to the Corporation's securities.

Volatility of Oil and Gas Prices and Markets

The Corporation's financial performance and condition are substantially dependent on the prevailing prices of oil and natural gas which are unstable and subject to fluctuation. Fluctuations in oil or natural gas prices could have an adverse effect on the Corporation's operations and financial condition and the value and amount of its reserves. Prices for crude oil fluctuate in response to global supply of and demand for oil, market performance and uncertainty and a variety of other factors which are outside the control of the Corporation including, but not limited, to the world economy and OPEC's ability to adjust supply to world demand, government regulation, political stability and the availability of alternative fuel sources. Natural gas prices are influenced primarily by factors within North America, including North American supply and demand, economic performance, weather conditions and availability and pricing of alternative fuel sources. In addition, the marketability of the production depends upon the availability and capacity of gathering systems and pipelines, the effect of federal and provincial regulation on such production and general economic conditions. All of these factors are beyond the control of the Corporation.

Decreases in oil and natural gas prices typically result in a reduction of the Corporation's net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of the Corporation's reserves. Any substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in the Corporation's net production revenue, cash flows and profitability and have a material adverse effect on the Corporation's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Corporation will in part be determined by the Corporation’s borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of its bank debt be repaid.

From time to time the Corporation has and may in the future 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, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases.

Current Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Capital Markets

As a result of the weakened global economic situation, the Corporation, along with all other oil and gas entities, may have restricted access to capital, bank debt and equity, and is likely to face increased borrowing costs. Although the Corporation's business has not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of funds generated from operations, borrowings and possible future equity sales, the Corporation's ability to make such capital expenditures will be dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and the Corporation's securities in particular.

To the extent that external sources of capital become limited or 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 materially and adversely affected as a result.

If funds generated from operations are lower than expected or capital costs for these projects exceed current estimates, or if the Corporation incurs major unanticipated expenses related to development or maintenance of its existing properties, it will be required to seek additional capital to maintain its capital expenditures at planned levels. 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.

Development of Additional Reserves

The Corporation's future success is dependent upon its ability to explore, develop or acquire additional oil and natural gas reserves that are economically recoverable at attractive acquisition prices. Except to the extent that the Corporation conducts successful activities or acquires properties containing proved reserves, or both, the proved reserves and production will generally decline as reserves are produced. If prevailing oil and natural gas prices were to increase significantly, the Corporation's costs to add reserves could be expected to increase. The drilling of oil and natural gas wells involves a high degree of risk, especially the risk of a dry hole or of a well that is not sufficiently productive to provide an economic return on the capital expended to drill the well.

Exploitation and development risks are due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploitation efforts in areas in which the Corporation has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three dimensional seismography, reservoir simulation studies and horizontal drilling may, where appropriate, be used by the Corporation to improve its ability to find, develop and produce oil and natural gas.

Title

Although satisfactory title reviews of the Corporation's properties are conducted in accordance with industry standards, those title reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Corporation to a property.

Environmental Concerns

The operation of oil and natural gas wells involves a number of natural hazards which may result in blowouts, environmental damage or other unexpected or dangerous conditions resulting in liability to the Corporation and possibly liability to third parties. Companies operating in the oil and natural gas industry are subject to extensive environmental regulation which provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in fines or the issuance of clean-up orders. See "Information Concerning the Oil and Natural Gas Industry – Environmental Regulation". The Corporation will make reasonable provision for well abandonment and reclamation where appropriate; however, there can be no assurance that such provision will be sufficient to satisfy all such obligations. No sinking fund or reserve will be established for the purpose of site reclamation or abandonment costs.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which controls and regulations may be amended from time to time. See "Information Concerning the Oil and Natural Gas Industry". Governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to establish legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada its emissions reduction targets slightly. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with legislation in Canada regulating emissions of greenhouse gases. The future implementation or modification of greenhouse gas regulations could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. 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. See "Information Concerning the Oil and Natural Gas Industry – Climate Change Regulation".

Reserves Estimates

Estimates 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. 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 and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves consultants have used both constant and forecast price and cost estimates in calculating reserves quantities for the Corporation's reserves. 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 therefrom will vary from the estimates contained in the applicable engineering reports. The reserves reports are based in part on the assumed success of activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in the applicable engineering reports will be reduced to the extent that such activities do not achieve the level of success assumed in the engineering reports.

Purchase of Reserves

Acquisitions of resource issuers and resource assets by the Corporation will be based on engineering and economic assessments made by management and reviewed by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other governmental levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. In particular, changes in the prices of and markets for oil and natural gas from those anticipated at the time of making such assessments will affect the value of the Corporation's securities. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than anticipated.

Depletion of Reserves

The Corporation's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on the Corporation's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are exploited, and from time to time production declines can be severe under certain conditions.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired.

There can be no assurance that the Corporation will be successful in developing or acquiring additional reserves on terms that meet the Corporation's investment objectives.

Foreign Exchange

Operating costs incurred by the Corporation are generally paid in Canadian dollars. World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact the Corporation's net production revenue. To the extent that the Corporation has engaged or will in the future engage in risk management activities related to commodity prices and foreign exchange rates, through entry into oil and natural gas price hedges and forward foreign exchange contracts or otherwise, the Corporation will be subject to unfavourable price changes and credit risks associated with the counter parties with which it contracts.

Potential Conflicts of Interest

Some of the directors of the Corporation are also directors of other oil and natural gas companies, which may from time to time be in competition with the Corporation for working interest partners, property acquisitions, or other limited resources. Where required by law, appropriate disclosure of such conflicts will be made by the applicable directors. In particular, the Corporation follows the provisions of the ABCA. These provisions state that in the event that a director has an interest in a contract or proposed contract or agreement, such 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 permitted by the ABCA.

Competition

The oil and natural gas industry is intensely competitive and the Corporation will compete for joint venture partners, capital, reserves acquisitions and skilled industry personnel with a substantial number of other companies which have greater resources. Many such companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a worldwide basis and as such have greater and more diverse resources upon which to draw. There is also competition between the oil industry and other industries with respect to the supply of energy and fuel to industrial, commercial and individual customers.

Operating Risks

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosions, blowouts and encountering formations with abnormal pressure and oil spills, the occurrence of any of which could result in substantial losses to the Corporation. The Corporation will maintain insurance against some, but not all, of these risks, in amounts which meet or exceed standard industry practice. There can be no assurance that any insurance will continue to be available at premium levels that justify its purchase or whether insurance will be available at all.

Continuing production from the Corporation's properties, and to some extent the marketing of production therefrom, are dependent upon the ability of the operator of such properties. To the extent that the operator of a property fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent or experiences cash flow problems.

Changes in Legislation

There can be no assurance that income tax laws, other laws or government incentive programs relating to the oil and gas industry, will not be changed in a manner which will adversely affect the Corporation. There can be no assurance that tax authorities having jurisdiction will agree with how the Corporation calculates its income for tax purposes or that such tax authorities will not change their administrative practices to the detriment of the Corporation.

Enforcement of Operating Agreements

Operations of the wells located on properties not operated by the Corporation are generally governed by operating agreements that typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to the Corporation.

Substantial Capital Requirements

The Corporation anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, the Corporation may have limited ability to expend 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. Moreover, future activities may require the Corporation to alter its capitalization significantly, including transactions involving the issuance of securities, which may be dilutive. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. 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. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to the Corporation.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards. 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 in the future on a timely basis to take advantage of business opportunities that may arise.

Insurance

The Corporation's involvement in the exploration for and development of oil and gas properties may result in the Corporation becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although the Corporation intends to obtain insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be 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 such 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, could have a material adverse effect on the Corporation's financial position, results of operations or prospects.

Reliance on Operators and Key Employees

To the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of the Corporation will be largely dependent upon the performance of its management and key employees. The Corporation does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Corporation.

Delays in Business Operations

In addition to the usual delays in payments by purchasers of oil and natural gas to the Corporation or to the operators, and the delays by operators in remitting payment to the Corporation, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of the Corporation in a given period and expose the Corporation to additional third party credit risks.

Permits and Licences

The operations of the Corporation may require licences and permits from various governmental authorities. There can be no assurance that the issuer will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its projects.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of the Corporation's assets, however, if a claim arose and was successful, it could have an adverse effect on the Corporation and its operations.

Seasonality

The level of activity in the Canadian oil and 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. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and potential declines in production of oil and gas of the Corporation.

Income Taxes

The Corporation will file all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all 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 a negative impact on current and future taxes payable and such impact may be material.

Borrowing

The Corporation's lenders have been provided with security over substantially all of the assets of the Corporation. If the Corporation becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell the Corporation's properties. The proceeds of any such sale would be applied to satisfy amounts owed to the Corporation's lenders and other creditors and only the remainder, if any, would be available to the Corporation.

Acquisition Risk

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

Additionally, the oil and gas property acquisition business is highly competitive, and is populated with many companies, large and small, with the capital and expertise to evaluate, purchase, and exploit producing and non-producing opportunities. Even with capital and experience, the industry risks of drilling dry holes and cost overruns are significant. Environmental compliance is an increasingly complex and costly burden to entry for many new exploration areas, and often times, and even if permits are obtained, they are sufficiently restrictive that a property cannot be explored to its full potential. The Corporation may not be able to locate acquisition opportunities, or finance those that the Corporation can. The Corporation offer no assurance that its entry into this business activity will be successful.

Third Party Credit Risk

The Corporation is or 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 could have a material adverse effect on the Corporation and its cash flow from operations.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

To the knowledge of the management of the Corporation, there are no outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to be contemplated, other than: (a) the statement of claim filed by Yangarra on December 11, 2009 in the Court of Queen's Bench of Alberta against a certain industry partner in the amount of $508,862 for a breach of the agreements between the parties, gross negligence and default of operator (the "**Claim**"); (b) the statement of defence and counterclaim in the amount of $1,236,457 to the Claim filed by the aforementioned industry partner on December 22, 2009 (the "**Counterclaim**"); and (c) statement of defence to the Counterclaim filed by Yangarra on January 14, 2010. On April 1, 2011, the Corporation amended its statement of claim. The Company increased the statement of claim based on the information provided by the defendant and expects the matter to go to trial during 2013.

In the normal conduct of operations, there are other pending claims by and against the Corporation. Litigation is subject to many uncertainties, and the outcome of individual matters is not predictable with assurance. In the opinion of management, based on the advice and information provided by its legal counsel, the final determination of these other litigations will not materially affect the Corporation.

Regulatory Actions

To the knowledge of management of the Corporation, no penalties or sanctions have been imposed by a court relating to securities legislation or by a securities regulatory body or by any other court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision, nor have any settlement agreements been entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as set out below, none of the directors, executive officers of the Corporation, any person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10 percent of any class or series of outstanding voting securities of the Corporation, nor any associate or affiliate of the foregoing persons had any material interest, direct or indirect, in any transaction during the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Corporation.

On March 17, 2010, the Corporation completed a non-brokered private placement of 80,000,000 Common Share Units at a price of $0.075 per Common Share Unit, for gross proceeds of $6,000,000. James Evaskevich, Gordon Bowerman, Dan Helman and Ron Gardiner subscribed for an aggregate of 13,356,669 Common Share Units for gross proceeds of $1,001,750 (16.7%) of the financing.

In March 2011 the Company, closed a "bought deal" financing, completed by way of a short form prospectus, for the sale of 23,632,500 Common Shares at a price of $0.73 per share for gross proceeds of $17,251,725. Management and directors subscribed for 753,500 shares for gross proceeds of $550,055 (3%) of the financing.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal office located in Calgary, Alberta.

MATERIAL CONTRACTS

The Corporation did not enter into any material contracts outside the ordinary course of business within the most recently completed financial year or prior thereto that are still in effect.

INTERESTS OF EXPERTS

Deloitte prepared the Deloitte Report referred to in this Annual Information Form. As of the date hereof, the partners, employees and consultants of Deloitte who participated in or who were in a position to directly influence the preparation of the Deloitte Report do not hold any of the securities of the Corporation.

KPMG LLP has confirmed that it is independent of the Corporation in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in the Corporation's information circular dated April 17, 2013. Additional financial information is also provided in the Corporation's consolidated financial statements and MD&A for the year ended December 31, 2012.

SCHEDULE "A"
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Yangarra Resources Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2012, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Management /Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Yangarra Resources Ltd. Reserve Estimation and Economic Evaluation	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue ($M, before income taxes, 10% discount rate)			
			Audited	**Evaluated**	**Reviewed**	**Total**
Deloitte LLP	December 31, 2012	Canada	**-**	**$167,381.0**	**-**	**$167,381.0**

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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

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

Executed as to our report referred to above:

Deloitte LLP
700, 850 – 2nd Street S.W.
Calgary, Alberta
T2P 3P8

(signed) "Douglas S. Ashton"
Douglas S. Ashton, P. Eng.
Associate Partner

Execution date: March 27, 2013

SCHEDULE "A"
REPORT OF MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

Management of Yangarra Resources Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

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

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation and, in the event of a proposal to change the independent qualified reserves evaluator, to inquire whether there had been disputes between the previous independent qualified reserves evaluator and management; 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 Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

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

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

(c) the content and filing of this report.

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

(signed) "James Evaskevich"	*(signed) "Michael d'Entremont"*
James Evaskevich	Michael d'Entremont
President and Chief Executive Officer	COO
(signed) "Robert Weir"	*(signed) "Gordon Bowerman"*
Robert Weir	Gordon Bowerman
Director	Director

March 27, 2013

SCHEDULE "C"

AUDIT COMMITTEE CHARTER

PURPOSE

The overall purpose of the Audit Committee (the **"Committee"**) of Yangarra Resources Ltd. (the **"Corporation"**) is to ensure that the Corporation's management has designed and implemented an effective system of internal financial controls, to review and report on the integrity of the consolidated financial statements and related financial disclosure of the Corporation and to review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of financial information. It is the intention of the Corporation's board of directors (the **"Board"**) that through the involvement of the Committee, the external audit will be conducted independently of the Corporation's management to ensure that the independent auditors serve the interests of shareholders rather than the interests of management of the Corporation. The Committee will act as a liaison to provide better communication between the Board and the external auditors. The Committee will monitor the independence and performance of the Corporation's independent auditors.

COMPOSITION, PROCEDURES AND ORGANIZATION

(1) The Committee shall consist of at least three members of the Board.

(2) At least three (3) members of the Committee shall be independent, who in the opinion of the Board, would be free from a relationship which would interfere with the exercise of the Committee members' independent judgment. At least one (1) member of the Committee shall have accounting or related financial management expertise. All members of the Committee that are not financially literate will work towards becoming financially literate to obtain a working familiarity with basic finance and accounting practices applicable to the Corporation. For the purposes of this Charter, an individual is financially literate if he or she 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.

(3) The Board, at its organizational meeting held in conjunction with each annual general meeting of the shareholders, shall appoint the members of the Committee for the ensuing year. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.

(4) Unless the Board shall have appointed a chair of the Committee, the members of the Committee shall elect a chair and a secretary from among their number.

(5) The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.

(6) The Committee shall have access to such officers and employees of the Corporation and to the Corporation's external auditors, and to such information respecting the Corporation, as it considers to be necessary or advisable in order to perform its duties and responsibilities.

(7) Meetings of the Committee shall be conducted as follows:

    (a) the Committee shall meet at least four times annually at such times and at such locations as may be requested by the chair of the Committee (the external auditors or any member of the Committee may also request a meeting of the Committee at any time);

    (b) the external auditors shall receive notice of and have the right to attend all meetings of the Committee; and

    (c) management representatives may be invited to attend all meetings except private sessions with the external auditors.

(8) The internal auditors and the external auditors shall have a direct line of communication to the Committee through its chair and may bypass management if deemed necessary. The Committee, through its chair, may contact directly any employee in the Corporation as it deems necessary, and any employee may bring before the Committee any matter involving questionable, illegal or improper financial practices or transactions.

ROLES AND RESPONSIBILITIES

(1) The overall duties and responsibilities of the Committee shall be as follows:

- (a) to assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and its approval of the Corporation's annual and quarterly consolidated financial statements and related financial disclosure;
- (b) to establish and maintain a direct line of communication with the Corporation's internal and external auditors and assess their performance;
- (c) to ensure that the management of the Corporation has designed, implemented and is maintaining an effective system of internal financial controls; and
- (d) to report regularly to the Board on the fulfilment of its duties and responsibilities.

(2) The duties and responsibilities of the Committee as they relate to the external auditors shall be as follows:

- (a) to recommend to the Board a firm of external auditors to be engaged by the Corporation, and to verify the independence of such external auditors;
- (b) to review and approve the fee, scope and timing of the audit and other related services rendered by the external auditors;
- (c) review the audit plan of the external auditors prior to the commencement of the audit;
- (d) to review with the external auditors, upon completion of their audit:
  - i. contents of their report;
  - ii. scope and quality of the audit work performed;
  - iii. adequacy of the Corporation's financial and auditing personnel;
  - iv. co-operation received from the Corporation's personnel during the audit;
  - v. internal resources used;
  - vi. significant transactions outside of the normal business of the Corporation;
  - vii. significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems; and
  - viii. the non-audit services provided by the external auditors;
- (e) to discuss with the external auditors the quality and not just the acceptability of the Corporation's accounting principles; and
- (f) to implement structures and procedures to ensure that the Committee meets the external auditors on a regular basis in the absence of management.

(3) The duties and responsibilities of the Committee as they relate to the internal control procedures of the Corporation are to:

- (a) review the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management;

(b) review compliance under the Corporation's business conduct and ethics policies and to periodically review these policies and recommend to the Board changes which the Committee may deem appropriate;

(c) review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Corporation; and

(d) periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal audit staff or by the external auditors have been implemented.

(4) The Committee is also charged with the responsibility to:

(a) review the Corporation's quarterly statements of earnings, including the impact of unusual items and changes in accounting principles and estimates and report to the Board with respect thereto;

(b) review and approve the financial sections of:

i. the annual report to shareholders;

ii. the annual information form, if required;

iii. annual and interim management's discussion and analysis;

iv. prospectuses;

v. news releases discussing financial results of the Corporation; and

vi. other public reports of a financial nature requiring approval by the Board,

and report to the Board with respect thereto;

(c) review regulatory filings and decisions as they relate to the Corporation's consolidated financial statements;

(d) review the appropriateness of the policies and procedures used in the preparation of the Corporation's consolidated financial statements and other required disclosure documents, and consider recommendations for any material change to such policies;

(e) review and report on the integrity of the Corporation's consolidated financial statements;

(f) review the minutes of any audit committee meeting of subsidiary companies;

(g) review with management, the external auditors and, if necessary, with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material effect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the consolidated financial statements;

(h) review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, tax matters and disclosure of financial information; and

(i) develop a calendar of activities to be undertaken by the Committee for each ensuing year and to submit the calendar in the appropriate format to the Board following each annual general meeting of shareholders.

(5) The Committee shall have the authority:

(a) to engage independent counsel and other advisors as it determines necessary to carry out its duties,

(b) to set and pay the compensation for any advisors employed by the Committee; and

(c) to communicate directly with the internal and external auditors.