ARC Resources Ltd.

2011 Annual Information Form

March 21, 2012

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GLOSSARY OF TERMS

In this Annual Information Form, capitalized terms shall have the meanings set forth below:

ARC, **we**, **us**, **our, Corporation** or **Trust** means ARC Resources and all its controlled entities as a consolidated body and, prior to the completion of the Trust Conversion, the Trust and all its controlled entities as a consolidated body;

ARC Partnership means ARC Resources General Partnership;

ARC Resources means ARC Resources Ltd., the corporation resulting from the amalgamation of ARC Energy Ltd., ARC Resources Ltd., 1485275 Alberta Ltd., ARC Petroleum Inc. and Smiley Gas Conservation Limited which occurred pursuant to the Trust Conversion;

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

Common Shares means the common shares in the capital of ARC Resources;

Exchangeable Shares means, prior to the completion of the Trust Conversion, the series A exchangeable shares and the series B exchangeable shares of ARC Resources Ltd.;

GLJ means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta;

GLJ Report means the report prepared by GLJ dated February 15, 2012 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to ARC's properties at December 31, 2011 and evaluating the natural gas and natural gas liquids resources located in the NE BC Montney;

Montney West or **West Montney** area means our lands west of the Dawson area in northeastern British Columbia comprised of the Sunrise, Sundown, Sunset, and Septimus areas;

NE BC Montney means our lands in northeastern British Columbia comprised of the Dawson, Parkland, Tower, Sunrise/Sunset, Attachie, Septimus, Sundown and Blueberry areas and our lands in northwestern Alberta in the Pouce Coupe area;

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

Shareholders means holders of Common Shares of ARC Resources.

Tax Act means the *Income Tax Act* (Canada);

Trust means ARC Energy Trust, the income trust which was reorganized into ARC Resources pursuant to the Trust Conversion;

Trust Conversion means the Plan of Arrangement under Section 193 of the *Business Corporations Act* (Alberta) involving, among others, the Trust, ARC Resources Ltd. and the security holders of the Trust and ARC Resources Ltd. which resulted in the reorganization of the Trust into a dividend paying, publicly traded exploration and production company, being ARC Resources, which together with its subsidiaries carries on the business formerly carried on by the Trust and its subsidiaries;

Trust Units means, prior to the completion of the Trust Conversion, the units of the Trust; and

TSX means the Toronto Stock Exchange.

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

SPECIAL NOTES TO READER

Regarding Forward Looking Statements and Risk Factors

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. In addition there are forward looking statements in this Annual Information Form under the headings: "Statement of Reserves Data and Other Oil and Gas Information" as to our reserves and future net revenues from our reserves, pricing and inflation rates and future development costs; "Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information" as to the development of our proved undeveloped reserves and probable undeveloped reserves, as to our future development activities, the status of our enhanced recovery projects, hedging policies, reclamation and abandonment obligation, tax horizon, exploration and development activities and production estimates; and under the heading "Statement of Reserves Data and Other Oil and Gas Information – Contingent Resource Estimates" as to our economic contingent resource estimates on our NE BC Montney properties. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In addition to the forward looking statements identified above, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to the performance characteristics of our oil and natural gas properties; oil and natural gas production levels; the size of the oil and natural gas reserves and of our economic contingent resources, projections of market prices and costs; expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; treatment under governmental regulatory regimes and tax laws; and capital expenditures programs.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. In addition, these risks and uncertainties are material factors affecting the success of our business. Such factors include, but are not limited to: declines in oil and natural gas prices; various pipeline constraints; the payment of dividends, if any; variations in interest rates and foreign exchange rates; uncertainties relating to the weakened global economy and consequential restricted access to capital, stock market volatility, market valuations and increased borrowing costs; refinancing risk for existing debt and debt service costs; access to external sources of capital; risks associated with our hedging activities; third party credit risk; risks associated with the exploitation of our properties and our ability to acquire reserves; government regulation and control and changes in governmental legislation; changes in income tax laws, royalty rates and other incentive programs; uncertainties associated with estimating oil and natural gas reserves and resources; risks associated with acquiring, developing and exploring for natural gas and other aspects of our operations; certain of our enhanced recovery projects are not currently economically feasible; risks associated with large projects or expansion of our activities; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; changes in climate change laws and other environmental regulations; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; risks of non-cash losses as a result of the application of accounting policies; our operating activities and ability to retain key personnel; depletion of our reserves; risks associated with securing and maintaining title to our properties; risks for United States and other non-resident Shareholders and other factors, many of which are beyond our control.

The actual results could differ materially from those results anticipated in these forward-looking statements, which are based on assumptions, including as to the market prices for oil and natural gas; the continuation of the present policies of the Board of Directors relating to management of ARC, and the payment of dividends, capital expenditures and other matters; the continued availability of capital, acquisitions of reserves, undeveloped lands and skilled personnel; the continuation of the current tax and regulatory regime and other assumptions contained in this Annual Information Form.

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

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements except as required by securities laws or regulations.

Access to Documents

Any document referred to in this Annual Information Form and described as being filed on SEDAR at *www.sedar.com* (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at 1200, 308 – 4th Avenue SW, Calgary, Alberta, T2P 0H7.

Abbreviations and Conversions

bbl	Barrel	Mcf	one thousand cubic feet
bbl/d	barrels per day	Mcfpd	one thousand cubic feet per day
Bcf	billion cubic feet	$MM	one million dollars
Bcfe	billion cubic feet equivalent converting one million barrels of oil or natural gas liquids into 6 billion cubic feet equivalent of natural gas	MMBTU	one million British Thermal Units
		MMcf	one million cubic feet
boe	barrels of oil equivalent converting 6 Mcf of natural gas or one barrel of natural gas liquids to one barrel of oil equivalent	MMcfpd	one million cubic feet per day
		MMbbl	one million barrels
boe/d	barrels of oil equivalent per day	NGLs	natural gas liquids
Mbbl	one thousand barrels	Tcf	one trillion cubic feet
mboe	one thousand barrels of oil equivalent		

We have adopted the standard of 6 Mcf:1boe when converting natural gas to boes. Boes may be misleading, particularly if used in isolation. **A boe conversion ratio of 6 Mcf per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value.**

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

To Convert From	To	Multiply By
cubic metres	cubic feet	35.315
bbls	cubic metres	0.159
cubic metres	bbls	6.290
Feet	metres	0.305
Metres	feet	3.281
Miles	kilometres	1.609
Kilometres	miles	0.621
Acres	hectares	0.4047
Hectares	acres	2.471

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

ARC RESOURCES LTD.

General

ARC Resources was formed by amalgamation under the *Business Corporations Act* (Alberta). Our principal office is located at 1200, 308 – 4th Avenue SW, Calgary, Alberta, T2P 0H7 and our registered office is located at 2400, 525 – 8th Avenue SW, Calgary, Alberta, T2P 1G1.

Prior to January 1, 2011, ARC was one of Canada's largest conventional oil and gas royalty trusts.

Currently, ARC is one of Canada's 15 largest conventional oil and gas companies with 2011 average production of 83,416 boe/d, all of which comes from western Canada. ARC has focused on the acquisition and development of resource rich properties that provide an option for near-term growth. ARC currently pays a monthly dividend to its Shareholders.

As at December 31, 2011, ARC had approximately 530 employees and consultants.

Business Activities

Strategy

ARC's business activities include the exploration for, development and production of crude oil, natural gas and natural gas liquids in western Canada. ARC's focus is on risk managed value creation through operational excellence and capital discipline. Our aim is to produce superior, long-term returns to Shareholders. At ARC, we utilize a disciplined approach to capital allocation and believe growth is not a mandate, but rather an option. ARC's goal is to develop new production and reserves while allocating a portion of our cash flow to pay out a monthly dividend to our Shareholders. On an annual basis ARC approves a capital budget with the objective of first replacing production declines and secondly increasing production and reserves. While much of our development activity is considered to be of a low risk nature, a percentage of each year's capital budget will be devoted to moderate risk development and low to moderate risk exploration opportunities to add value.

Our staff use their expertise combined with continuously evolving technologies to unlock additional reserves that will lead to future production through the exploration for and development of large oil and natural gas pools. We have policies for hiring and a staff succession, progression and development program to provide the in house expertise to fully exploit ARC's assets.

ARC's operating practices and procedures are aimed at maximizing reservoir recovery of oil and natural gas over time while controlling costs in a safe operating environment.

We have rigorous health and safety policies which set out procedures, practices and reporting of actions to assist in ensuring that ARC employees and contractors employ continuously improving safety measures and act in a safe and prudent manner. We also have policies which encompass the cleanup abandonment and site reclamation activities of ARC.

Financial Objectives

ARC's long-term financial objectives include the maintenance of a strong balance sheet with the target of keeping debt between one and 1.5 times funds from operations and under 20 per cent of total capitalization. In addition, ARC's risk management program actively hedges up to 55 per cent of our production for periods of up to two years to provide stability to funds from operations, a portion of which is paid out as monthly dividends with the remaining portion funding capital expenditures. Hedges in excess of 55 per cent of our production requires approval of the Board of Directors. The economics of specific projects and certain acquisitions may be hedged for periods longer than two years with Board of Directors approval.

The development of ARC's properties will require future capital expenditures, which will be financed through a combination of cash flow, proceeds from disposition of properties, borrowings, farm-outs, working capital or through the proceeds of the issuance of additional Common Shares.

ARC considers acquisitions of all types of petroleum and natural gas and other energy-related assets and the potential disposition of existing assets which are less strategic or have limited upside potential to be part of our ongoing business operations.

General Development of Our Business

A description of the general development of our business over the last three financial years follows:

2009

Production volumes were 63,538 boe/d and cash flow from operating activities was $497.4 million.

Distributions to investors decreased from $0.12 per Trust Unit in January 2009 to $0.10 per Trust Unit in February 2009 in light of continued low commodity prices and were maintained at this level of $0.10 per month for the remainder of the year resulting in a total of $298.5 million being distributed.

On February 6, 2009, the Trust closed an equity offering and issued 15.5 million Trust Units at $16.35 per Trust Unit. The net proceeds of the offering were $240 million and were used to reduce our bank indebtedness.

Capital expenditures were $518 million, of which $326.3 million (63 per cent) was development and facility capital expenditures and $17.4 million (3 per cent) was property acquisition costs, geological and geophysical expenditures, and drilling costs for exploratory wells. Total acquisitions, net of $20.5 million in dispositions, were $158.4 million.

In December of 2009, we completed a $178.9 million acquisition of assets in the Ante Creek area of northwestern Alberta. Through this acquisition, we acquired an average 75 per cent working interest in 26,000 gross acres of developed lands which include 38 net oil wells and 24 net gas wells, a 30 per cent interest in an ARC operated gas plant (which brought the interest of ARC Resources in such plant to 100 per cent) and 121,000 gross (106,000 net) acres of undeveloped lands. Production from these assets for the nine months ended September 30, 2009 was approximately 2,000 boe/d and was weighted approximately 75 per cent to natural gas and approximately 25 per cent to crude oil and natural gas liquids.

2010

Production was a record 73,954 boe/d while funds from operations were $667.0 million.

Distributions to investors were maintained at $0.10 per Trust Unit per month throughout the year resulting in a total of $313.4 million being distributed.

On January 5, 2010, the Trust closed an equity offering and issued 13 million Trust Units at $19.40 per unit. The net proceeds of the offering were $239.5 million and were used to reduce our bank indebtedness following the $178.9 million acquisition of assets in the Ante Creek area which closed in the middle of December 2009.

On August 17, 2010, ARC Resources Ltd. acquired all of the existing and outstanding common shares of Storm Energy Inc. ("**Storm**") pursuant to a plan of arrangement under the provisions of Section 192 of the *Canada Business Corporations Act* involving Storm, Storm Resources Ltd., the Trust and ARC Resources Ltd. (the "**Storm Arrangement**"). The transaction was valued at approximately $652.1 million (including the assumption of debt) based on the August 17, 2010 closing price of $19.53 per Trust Unit. Storm's primary asset was the Parkland field in northeastern British Columbia, a Montney gas field located approximately 10 km from ARC's Dawson field. Production from the Storm assets averaged 7,800 boe per day over the last four months of 2010.

Pursuant to the Storm Arrangement, the Trust issued 23,514,456 Trust Units and ARC Resources issued 1,744,038 series B exchangeable shares (which shares, as at the closing date, were exchangeable for 4,927,797 Trust Units) to holders of Storm shares and assumed approximately $89 million of total net debt.

Capital expenditures were $1,248.0 million, of which $652.1 million was the Storm Arrangement, $477.2 million (38 per cent) was development and facility capital expenditures; $77.5 million (6 per cent) was property acquisition costs, geological and geophysical expenditures, and drilling costs for exploratory wells. $24.6 million was spent on corporate leasehold costs for new office space.

In the second quarter, ARC started up the 60 MMcfpd Dawson Phase 1 gas plant.

2011

The Trust Conversion was completed on January 1, 2011 and resulted in the reorganization of the Trust into ARC Resources, a new publicly traded exploration and development corporation formed upon the amalgamation of ARC Energy Ltd., ARC Resources Ltd., 1485275 Alberta Ltd., ARC Petroleum Inc. and Smiley Gas Conservation Limited.

In accordance with the terms of the Trust Conversion, the holders ("**Unitholders**") of Trust Units of the Trust received, through a series of steps, one Common Share of ARC Resources for each Trust Unit held and the holders of Exchangeable Shares of ARC Resources Ltd. received, through a series of steps, 2.89162 Common Shares of ARC Resources for each Exchangeable Share held, such number being the exchangeable share ratio of the Exchangeable Shares as at December 31, 2010. In addition, pursuant to the Trust Conversion, the Trust was dissolved and ARC Resources acquired all of the assets of the Trust and ARC Resources assumed all of the liabilities of the Trust.

Following the Trust Conversion, ARC Resources, together with its subsidiaries, carries on the business formerly carried on by the Trust and its subsidiaries.

The Common Shares of ARC Resources began trading on the TSX under the trading symbol ARX on January 6, 2011. Beginning with the payment of dividends to Shareholders of ARC of record on January 31, 2011, Shareholders of ARC receive payments in the form of dividends. Prior to the conversion of the Trust to a corporation on December 31, 2010, distributions were paid to unitholders. Previous historical references to "unitholders", "distributions" "trust units", and "per unit" have now been replaced by "Shareholders", "dividends", "Common Shares", and "per share", respectively where applicable.

Despite the change in legal structure from a trust to a dividend paying corporation, ARC's business activities and business strategy remained unchanged and the board of directors and officers at the time of the Trust Conversion remained the same.

Production was a record 83,416 boe/d while funds from operations were $844.3 million.

Dividends to investors were maintained at $0.10 per share per month throughout the year resulting in a total of $344.1 million being distributed.

In the second quarter of 2011, ARC commissioned the 60 MMcfpd Dawson Phase 2 gas plant, increasing operated plant capacity at Dawson from 60 MMcfpd to 120 MMcfpd. Dawson production increased to 165 MMcfpd during 2011, with 120 MMcfpd processed at the ARC gas plants and 45 MMcfpd processed at third party facilities.

Capital expenditures were $726 million, of which $585.3 million (81 per cent) was development and facility capital expenditures, $74.9 million was spent to acquire land, $52.3 million were on geological and geophysical expenditures and drilling costs for exploratory wells, the remaining $13.5 million was for corporate capital spending.

During 2011, ARC divested of certain non-core properties for proceeds of $170 million plus 36 sections of land in the Ante Creek region.

ARC renegotiated and extended its syndicated revolving credit facility to a four year term in 2011. ARC had total credit capacity of $1.6 billion at December 31, 2011. Net debt to annualized year-to-date funds from operations ratio was 1.1 times and net debt was approximately 11 per cent of ARC's total capitalization at the end of 2011; both well within our target levels.

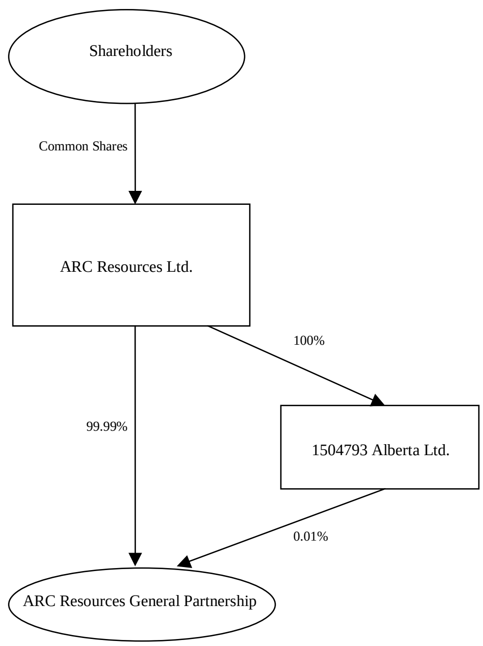
Recent Developments

On February 8, 2012, ARC announced that it had retained a qualified advisor to assist with the sale process for a certain portion of ARC's NE BC Montney land base. The lands being offered for sale are less strategic project areas, representing approximately 10 per cent of ARC's total NE BC Montney land base. A sale will only occur if an offer is received which represents superior value relative to our view of value attainable from our own development plan.

Our Organizational Structure

The ARC Partnership owns substantially all of our oil and natural gas properties and is owned 100 per cent directly or indirectly by ARC Resources. ARC Resources is the manager of the ARC Partnership. The ARC Partnership is a general partnership formed under the laws of Alberta.

The following diagram sets forth the organizational structure of ARC:



STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information is set forth below (the "**Statement**"). The effective date of the Statement is December 31, 2011 and the preparation date of the Statement is January 17, 2012. The Report on Reserves Data by GLJ on Form 51-102F2 and the Report of Management and Directors on Reserves Data and Other Information on Form 51-101F3 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by GLJ with an effective date of December 31, 2011 contained in the GLJ Report dated February 15, 2012. The reserves data summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves, using forecast prices and costs prior to provision for interest, general and administrative expenses, the impact of any hedging activities or the liability associated with certain abandonment and well, pipeline and facilities reclamation costs which were not deducted by GLJ in estimating future net revenue. Future net revenues have been presented on a before and after tax basis. The reserves data conforms with the requirements of NI 51-101. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves. See also "*Definitions and Notes to Reserves Data Tables*" below.

All of our reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "Definitions and Notes to Reserves Data Tables" in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors – Risk Relating to Our Business and Operations*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2011
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	87,626	75,293	1,874	1,801
Developed Non-Producing	1,794	1,587	-	-
Undeveloped	12,768	11,025	-	-
TOTAL PROVED	102,188	87,905	1,874	1,801
PROBABLE	32,883	27,511	434	419
TOTAL PROVED PLUS PROBABLE	135,071	115,416	2,308	2,220

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Bcf)	Net (Bcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	655	556	10,210	7,640
Developed Non-Producing	44	38	756	626
Undeveloped	719	604	8,122	6,736
TOTAL PROVED	1,419	1,197	19,088	15,002
PROBABLE	994	804	13,686	10,953
TOTAL PROVED PLUS PROBABLE	2,413	2,001	32,774	25,955

	RESERVES	
	TOTAL	
RESERVES CATEGORY	Gross (mboe)	Net (mboe)
PROVED		
Developed Producing	208,920	177,318
Developed Non-Producing	9,952	8,485
Undeveloped	140,769	118,362
TOTAL PROVED	359,641	304,165
PROBABLE	212,733	172,863
TOTAL PROVED PLUS PROBABLE	572,374	477,028

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]				
	0 ($MM)	5 ($MM)	10 ($MM)	15 ($MM)	20 ($MM)	0 ($MM)	5 ($MM)	10 ($MM)	15 ($MM)	20 ($MM)
PROVED										
Developed Producing	6,954	4,750	3,662	3,014	2,583	5,888	4,117	3,229	2,693	2,332
Developed Non-Producing	301	214	168	140	121	224	160	125	104	90
Undeveloped	2,678	1,572	975	620	393	1,999	1,131	662	384	208
TOTAL PROVED	9,933	6,536	4,805	3,774	3,097	8,112	5,407	4,016	3,181	2,630
PROBABLE	6,365	3,021	1,715	1,084	735	4,752	2,227	1,239	764	502
TOTAL PROVED PLUS PROBABLE	16,298	9,557	6,520	4,858	3,832	12,863	7,635	5,255	3,945	3,132

Note:

(1) The after-tax net present value of ARC's oil and gas properties presented here reflect the income tax burden on the properties on a stand-alone basis. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the net present value at the level of the business entity, which may be significantly different. ARC's Consolidated Financial Statements and Management's Discussion and Analysis should be consulted for information at the business entity level.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($MM)	ROYALTIES ($MM)	OPERATING COSTS ($MM)	DEVELOPMENT COSTS ($MM)	ABANDONMENT AND RECLAMATION COSTS ($MM)	FUTURE NET REVENUE BEFORE INCOME TAXES ($MM)	INCOME TAXES ($MM)	FUTURE NET REVENUE AFTER INCOME TAXES ($MM)
Proved Reserves	21,652	3,298	6,323	1,847	251	9,933	1,821	8,112
Proved Plus Probable Reserves	34,527	5,578	9,239	3,112	300	16,298	3,435	12,863

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($MM)	PER UNIT[3]
Proved Reserves	Light and Medium Crude Oil[1]	2,725	$26.10/bbl
	Heavy Oil[1]	58	$32.69/bbl
	Natural Gas[2]	2,022	$1.70/Mcf
	Total	4,805	
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	3,398	$24.52/bbl
	Heavy Oil[1]	67	$30.83/bbl
	Natural Gas[2]	3,054	$1.51/Mcf
	Total	6,520	

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.
(3) Unit values are based on Company Net Reserves.

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "**Gross**" means:

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

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

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

2. "**Net**" means:

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

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

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

3. Columns may not add due to rounding.

4. The crude oil, natural gas liquids and natural gas reserves estimates presented in the GLJ Report are based on the definitions and guidelines contained in the CSA Notice 51-324 – Glossary to NI 51-101 *Standards of Disclosure for Oil and Gas Activities* and the COGE Handbook. A summary of those definitions are set forth below:

   Reserves Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions.

   Reserves are classified according to the degree of certainty associated with the estimates.

   (a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   (b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

   Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories:

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

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

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

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

5. **Forecast Prices and Costs**

These are prices and costs that are generally acceptable as being a reasonable outlook of the future as of the evaluation effective date. To the extent that there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs shall be incorporated into the forecast prices.

The forecast cost and price assumptions include increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, natural gas and natural gas liquids benchmark reference pricing, as at December 31, 2011, inflation and exchange rates utilized in the GLJ Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2011
FORECAST PRICES AND COSTS

	OIL					EDMONTON LIQUIDS PRICES				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMbtu)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	INFLATION RATES(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast										
2012	97.00	97.96	72.37	90.12	3.49	58.78	76.41	107.76	2%	0.980
2013	100.00	101.02	73.60	92.94	4.13	60.61	78.80	108.09	2%	0.980
2014	100.00	101.02	74.51	91.93	4.59	60.61	78.80	105.06	2%	0.980
2015	100.00	101.02	74.51	91.93	5.05	60.61	78.80	105.06	2%	0.980
2016	100.00	101.02	74.51	91.93	5.51	60.61	78.80	105.06	2%	0.980
2017	100.00	101.02	74.51	91.93	5.97	60.61	78.80	105.06	2%	0.980
2018	101.35	102.40	75.54	93.18	6.21	61.44	79.87	106.49	2%	0.980
2019	103.38	104.47	77.09	95.07	6.33	62.68	81.49	108.65	2%	0.980
2020	105.45	106.58	78.67	96.99	6.46	63.95	83.13	110.84	2%	0.980
2021	107.56	108.73	80.28	98.95	6.58	65.24	84.81	113.08	2%	0.980
Thereafter	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	2%	0.980

Notes:
(1) Inflation rates for forecasting costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.
(3) Prices escalate 2.0% per year from 2021.

Weighted average actual prices realized for the year ended December 31, 2011, were $3.83/Mcf for natural gas, $90.05/bbl for light and medium crude oil, $73.29/bbl for heavy crude oil and $69.68/bbl for natural gas liquids. Only a minor amount of our production is characterized as heavy oil.

6. Future Development Costs

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

Year	Proved Reserves ($MM)	Proved Plus Probable Reserves ($MM)
2012	301.4	448.2
2013	520.6	650.1
2014	325.7	496.5
2015	328.0	544.5
2016	206.3	287.2
Remainder	165.4	685.1
Total: Undiscounted	1,847.4	3,111.6
Total: Discounted at 10%/year	1,443.7	2,299.5

We expect to fund the development costs of the reserves through a combination of cash flow from operating activities, debt, the sale of existing less-strategic assets and the issuance of Common Shares.

Estimates of reserves and future net revenue have been made assuming the development of each property, in respect of which the estimate is made, will occur, without regard to the likely availability to us of funding required for the development. There can be no guarantee that funds will be available or that we will allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves would have a negative impact on future cash flow from operating activities.

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

7. Estimated future well abandonment costs related to reserves wells have been taken into account by GLJ in determining the aggregate future net revenue therefrom.

8. The forecast price and cost assumptions assumed the continuance of current laws and regulations.

9. All factual data supplied to GLJ was accepted as represented. No field inspection was conducted.

Reconciliations of Changes in Reserves

The following table sets forth the reconciliation of our gross reserves as at December 31, 2011, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2011 and as at December 31, 2010 include working interest reserves before royalties payable and without including gross royalties receivable.

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

	LIGHT AND MEDIUM OIL			HEAVY OIL			NATURAL GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Bcf)	Probable (Bcf)	Proved Plus Probable (Bcf)
December 31, 2010	103,104	33,750	136,854	2,105	672	2,777	1,265.4	649.6	1,914.9
Discoveries	61	131	192	0	0	0	6.7	3.0	9.7
Extensions	4,015	2,733	6,748	0	0	0	218.1	319.4	537.5
Infill Drilling	5,157	714	5,871	30	(30)	0	41.6	14.4	55.9
Improved Recovery	451	(152)	299	0	0	0	0.3	(0.1)	0.2
Technical Revisions	529	(3,408)	(2,879)	1	(208)	(207)	131.3	(18.1)	113.2
Acquisitions	21	11	32	6	0	6	8.9	16.6	25.5
Dispositions	(1,465)	(899)	(2,364)	0	0	0	(55.5)	(25.5)	(81.0)
Economic Factors	(150)	3	(147)	0	0	0	(85.4)	35.1	(50.3)
Production	(9,535)	0	(9,535)	(268)	0	(268)	(112.3)	0	(112.3)
December 31, 2011	102,188	32,883	135,071	1,874	434	2,308	1,418.9	994.4	2,413.3

FACTORS	NATURAL GAS LIQUIDS Proved (Mbbl)	NATURAL GAS LIQUIDS Probable (Mbbl)	NATURAL GAS LIQUIDS Proved Plus Probable (Mbbl)	TOTAL Proved (mboe)	TOTAL Probable (mboe)	TOTAL Proved Plus Probable (mboe)
December 31, 2010	18,329	8,003	26,332	334,432	150,689	485,121
Discoveries	465	204	669	1,643	832	2,475
Extensions	2,822	5,996	8,818	43,195	61,956	105,151
Infill Drilling	380	80	460	12,493	3,157	15,651
Improved Recovery	26	0	26	524	(160)	364
Technical Revisions	1,544	(101)	1,443	23,949	(6,727)	17,222
Acquisitions	47	87	134	1,550	2,864	4,415
Dispositions	(2,447)	(741)	(3,188)	(13,165)	(5,891)	(19,056)
Economic Factors	(458)	158	(300)	(14,845)	6,017	(8,828)
Production	(1,620)	0	(1,620)	(30,137)	0	(30,137)
December 31, 2011	19,088	13,686	32,774	359,641	212,733	572,374

Additional Information Relating to Reserves Data

Proved and Probable Undeveloped Reserves

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

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

Proved Undeveloped Reserves

	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Prior	7,919	7,919	-	-	268,684	268,684	2,000	2,000	54,700	54,700
2009	2,093	8,655	-	-	118,891	388,364	642	2,636	22,550	76,018
2010	4,299	11,085	30	30	223,762	543,518	4,259	6,193	45,882	107,894
2011	5,405	12,768	-	-	209,126	719,277	2,620	8,122	42,880	140,770

Probable Undeveloped Reserves

	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Prior	8,511	8,511	93	93	153,050	153,050	1,346	1,346	35,458	35,458
2009	4,244	10,435	-	100	156,403	299,771	840	2,083	31,151	62,580
2010	7,477	12,523	-	150	155,242	439,484	2,589	4,768	35,940	90,689
2011	4,299	10,976	-	-	350,542	787,242	6,205	10,667	68,927	152,850

Undeveloped reserves represent 39 per cent of total proved reserves and 51 per cent of proved plus probable reserves. Over 91 per cent of the proved plus probable undeveloped reserves are located in the Dawson, Montney West, Ante Creek, Parkland, and Attachie area properties. In each case, we have planned a program for the development of a portion of the undeveloped reserves in these areas in 2012 and beyond.

In some cases it will take us longer than two years to develop these reserves. We plan to develop the majority of the proved undeveloped reserves in the reserves evaluation over the next four years and plan to develop the majority of the probable undeveloped reserves over the next six years. The pace of development of these reserves is influenced by many factors, including the ongoing development of the infrastructure in the Attachie and Montney West areas, the outcomes of the yearly drilling and reservoir evaluations, the price for oil and natural gas, and a variety of economic factors.

There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access, issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors – Risk Relating to Our Business and Operations"*.

Significant Factors or Uncertainties

We have a significant amount of proved undeveloped and probable reserves assigned to the NE BC Montney. Sophisticated and expensive technology and large capital expenditures are required for these wells to produce. At the current depressed natural gas prices, many of these wells are un-economic.

Degradation in future commodity price forecasts relative to the forecast in the GLJ Report can also have a negative impact on the economics of the development of undeveloped reserves, unless significant reduction in the future costs of development are realized.

Other Oil and Gas Information

Our portfolio of properties as at December 31, 2011 includes both unitized and non-unitized oil and natural gas production. In general, the properties contain long-life, low decline rate reserves and include interests in several major oil and gas fields.

Principal Properties

The following is a description of our principal oil and natural gas properties as at December 31, 2011. Reserves amounts are stated at December 31, 2011, based on escalated cost and price assumptions as evaluated in the GLJ Report prepared by GLJ (see "*Statement of Reserves Data and Other Oil and Gas Information*"). Information in respect of gross and net acres and well counts are as at December 31, 2011, and information in respect of production is for the year ended December 31, 2011 except where indicated otherwise. Due to the fact that we have been active at acquiring additional interests in our principal properties, the working interest share and interest in gross and net acres and wells as at December 31, 2011 may not directly correspond to the stated production for the year, which only includes production since the date the interests were acquired by us. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

All of the properties described below are located in the Western Canadian Sedimentary Basin and within the Canadian provinces of British Columbia, Alberta or Saskatchewan. The properties described below comprise 80 per cent of the total gross proved plus probable reserves as assigned by GLJ in the GLJ Report. Approximately 60 per cent of total gross proved plus probable reserves for the described properties are located in the Province of British Columbia. There are no other properties which individually account for more than 1.7 per cent of the total gross proved plus probable reserves as assigned by GLJ in the GLJ Report. Except as set forth under the heading "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Proved and Probable Undeveloped Reserves*", there are no other material properties to which reserves have been attributed that are capable of producing but which are not producing at December 31, 2011 and there are no material statutory or mandatory relinquishments, surrenders, back-ins or changes in ownership provisions.

	2011 Company Gross Reserves and Company Gross Production							
	Light & Medium Crude Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	Total Oil Equivalent Production	Proved Reserves	Proved Plus Probable Reserves	
	(bbl/d)	(bbl/d)	(MMcfpd)	(bbl/d)	(boe/d)	(mboe)	(mboe)	(%)
Dawson [(1)]	-	-	133.6	632	22,900	112,370	173,695	30.3%
Parkland-Tower	19	-	42.1	1,043	8,078	30,156	54,211	9.5%
Ante Creek	2,777	42	23.9	639	7,440	29,974	47,165	8.2%
Redwater	3,837	-	1.2	130	4,171	20,938	25,556	4.5%
Berrymoor Cardium Unit	1,598	-	2.0	134	2,061	7,771	9,622	1.7%
Montney West	1	-	12.0	8	2,006	38,682	95,519	16.7%
Lougheed	1,847	-	-	61	1,908	4,867	6,059	1.1%
North Pembina Cardium Unit	1,556	-	1.0	90	1,806	11,211	13,075	2.3%
Weyburn Unit	1,746	-	-	-	1,746	10,197	14,878	2.6%
Attachie	-	-	-	-	-	5,987	15,953	2.8%

(1) Includes Doe property reserves and production.

Dawson

The Dawson property is located in northeast British Columbia. We are the operator and own an average land interest of 92.2 per cent in approximately 43,877 gross hectares (40,444 net hectares). We operate a large area compression facility where the natural gas and liquids are processed through an operated 120 MMcfpd gas plant and third party facilities. During 2011, gross production from the area averaged 22,901 boe/d of natural gas and natural gas liquids from 138 net wells. During 2011, 12 new wells were drilled. GLJ assigned gross proved reserves of 112,370 mboe and gross proved plus probable reserves of 173,695 mboe of natural gas and natural gas liquids to this area, representing 30.3 per cent of total gross proved plus probable reserves.

Parkland-Tower

The Parkland-Tower property is located in northeast British Columbia. We own an average land interest of 74.5 per cent in approximately 29,728 gross hectares (22,171 net hectares) in the Parkland-Tower area. The Parkland-Tower Area has been assigned gross proved reserves of 30,156 boe and gross proved plus probable reserves of 54,211 mboe, representing 9.5 per cent of total gross proved plus probable reserves in the GLJ Report. On a full year basis, gross production from the area averaged 8,078 boe/d of oil, natural gas and natural gas liquids from 62 net wells. During 2011, 13 new wells were drilled. We operate a compression facility and utilize an operated gas plant and third party facilities to process natural gas and natural gas liquids.

Ante Creek

The Ante Creek property is located in northwest Alberta. We are the operator and own an average land interest of 97.5 per cent in approximately 80,608 gross hectares (78,623 net hectares). Oil production is processed through three operated facilities, while the gas is processed through one operated facility and one third party facility. During 2011, gross production from the area averaged 7,440 boe/d of oil, natural gas and natural gas liquids from 228 net wells. During 2011, 20 new wells were drilled. GLJ assigned gross proved reserves of 29,974 mboe and gross proved plus probable reserves of 47,165 mboe of oil, natural gas and natural gas liquids to this area, representing 8.2 per cent of total gross proved plus probable reserves.

Redwater

The Redwater property is located in central Alberta. We are the operator and own an average land interest of 84.6 per cent in approximately 23,105 gross hectares (19,550 net hectares). Oil and solution gas are both processed at an operated central facility. During 2011, gross production from the area averaged 4,177 boe/d of oil, natural gas and natural gas liquids from 402 net wells. During 2011, 18 new wells were drilled. GLJ assigned gross proved reserves of 20,938 mboe and gross proved plus probable reserves of 25,556 mboe of oil, natural gas and natural gas liquids to this area, representing 4.5 per cent of total gross proved plus probable reserves.

During 2011, ARC continued production operations at the EOR pilot project in Redwater. The pilot was designed to confirm whether the Redwater reef is amenable to CO_2 flooding and if incremental oil can be mobilized and recovered. The CO2 injection phase of the pilot has been completed, while the observation of producing wells continues. Prior to commercial operations, large amounts of CO_2 need to be acquired on economic terms for the Redwater EOR project to proceed. There is no assurance that the Redwater EOR project will proceed to a commercial phase or become economically viable.

Berrymoor Cardium Unit

The Berrymoor Cardium Unit is located in central Alberta. We are the operator and own a 73.3 per cent interest in the unit. Oil is processed at an operated battery while the solution gas flows to third party facilities. During 2011, gross production from the unit averaged 2,061 boe/d of oil, natural gas and natural gas liquids from 97 net wells. During 2011, two new wells were drilled. GLJ assigned gross proved reserves of 7,771 mboe and gross proved plus probable reserves of 9,622 mboe of oil, natural gas and natural gas liquids to this unit, representing 1.7 per cent of total gross proved plus probable reserves.

Montney West

The Montney West property is located in northeast British Columbia. We own an average land interest of 79.9 per cent in approximately 25,671 gross hectares (20,511 net hectares) in the Montney West area. During 2011, four new wells were drilled. The Montney West area has been assigned gross proved reserves of 38,682 mboe and gross proved plus probable reserves of 95,519 mboe in the GLJ Report, representing 16.7 per cent of total gross proved plus probable reserves. During 2011, gross production from the area averaged 2,007 boe/d of natural gas and natural gas liquids, processed through third party facilities.

Lougheed

The Lougheed property is located in southeast Saskatchewan. We are the operator and own an average land interest of 87.0 per cent in approximately 6,487 gross hectares (5,643 net hectares) . Production is handled by an operated battery and gas plant. During 2011, gross production from the area averaged 1,909 boe/d of oil and natural gas liquids from 123 net wells. During 2011, one new well was drilled. GLJ assigned gross proved reserves of 4,867 mboe and gross proved plus probable reserves of 6,059 mboe of oil and natural gas liquids to this area, representing 1.1 per cent of total gross proved plus probable reserves.

North Pembina Cardium Unit

The North Pembina Cardium Unit is located in central Alberta. We are the operator and own a 45.6 per cent interest in the unit. Production is processed through two operated oil treatment facilities, one operated and one non-operated solution gas plant. During 2011, gross production from the unit averaged 1,806 boe/d of oil, natural gas and natural gas liquids from 181 net wells. During 2011, five new wells were drilled. GLJ assigned gross proved reserves of 11,211 mboe and gross proved plus probable reserves of 13,075 mboe of oil, natural gas and natural gas liquids to this unit, representing 2.3 per cent of total gross proved plus probable reserves.

Weyburn Unit

The Weyburn Unit is located in southeast Saskatchewan. Cenovus Energy Inc. operates the unit and we have a working interest of 6.9 per cent. The unit is currently undergoing a CO_2 flood for enhanced oil recovery. During 2011 gross production from the unit averaged 1,749 boe/d of oil from 48 net wells. GLJ assigned gross proved reserves of 10,197 mboe and gross proved plus probable reserves of 14,878 mboe of oil and natural gas liquids to this unit, or 2.6 per cent of our total gross proved plus probable reserves.

Attachie

The Attachie property is located in northeast British Columbia. We own a land interest of 100 per cent in approximately 30,707 hectares in the area. The Attachie property has been assigned gross proved reserves of 5,987 mboe and gross proved plus probable reserves of 15,953 mboe in the GLJ Report or 2.8 per cent of our total gross proved plus probable reserves. During 2011, three horizontal Montney wells and two vertical wells were drilled across the large land base. We are currently evaluating opportunities to bring a small amount of production on-stream through third party facilities. Large scale development in this area will require significant infrastructure investments including pipelines and processing facilities.

Our portfolio of properties as at December 31, 2011 includes both unitized and non-unitized oil and natural gas production. In general, the properties contain long-life, low decline rate reserves and include interests in several major oil and gas fields.

Contingent Resource Estimates

ARC engaged GLJ to provide an evaluation of, among other things, our Economic Contingent Resources (as defined below) for our working interest in our NE BC Montney properties, effective December 31, 2011. We own an average 90 per cent working interest in our NE BC Montney properties. The following table sets forth arithmetic sums of the estimates of the Economic Contingent Resources for natural gas and natural gas liquids contained in the GLJ Report for ARC's interest for our NE BC Montney properties. The evaluation procedures employed by GLJ are in compliance with standards contained in the COGE Handbook and the GLJ Report is based on GLJ's January 1, 2012 pricing. See "*Statement of Reserves Data and Other Oil and Gas Information - Definitions and Notes to Reserves Data Tables*".

The estimates of Economic Contingent Resources should not be confused with reserves and readers should review the definitions and notes set forth below. Actual natural gas and natural gas liquids resources may be greater than or less than the estimates provided herein. There is no certainty that it will be commercially viable to produce any portion of the resources.

	Estimated Economic Contingent Resource(1)(5)(6)		
	Low Estimate(2)	Best Estimate(3)	High Estimate(4)
Natural Gas (Tcf)	2.5	4.1	5.7
Natural Gas Liquids (Mmbbls)	64.2	101.0	133.9

Notes:

(1) "**Contingent Resources**" are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "**Contingent Resources**" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub classified based on project maturity and/or characterized by their economic status. "**Economic Contingent Resources**" are those Contingent Resources that are currently economically recoverable.

(2) "**Low Estimate**" is a classification of estimated resources described in the COGE Handbook as being considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the Low Estimate. If probabilistic methods are used, there should be a 90 per cent probability (P90) that the quantities actually recovered will equal or exceed the Low Estimate.

(3) "**Best Estimate**" is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be 50 per cent probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

(4) "**High Estimate**" is a classification of estimated resources described in the COGE Handbook as being considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the High Estimate. If probabilistic methods are used, there should be a 10 per cent probability (P10) that the quantities actually recovered will equal or exceed the High Estimate.

(5) Based on the GLJ Report and effective as of December 31, 2011 and based on Company Gross volumes.

(6) These volumes are arithmetic sums of multiple estimates of contingent resources, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class as explained. In particular, readers should be aware that the likelihood of attaining the sum of the High Estimate is extremely low and of the Low Estimate quite high.

Continuous development through multi-year exploration and development programs and significant levels of future capital expenditures are required in order for Economic Contingent Resources to be recovered in the future. The principal risks that would inhibit the recovery of additional reserves relate to the potential for variations in the quality of the Montney formation where minimal well data currently exists, access to the capital which would be required to develop the resources, low natural gas prices that would curtail the economics of development and the future performance of wells, regulatory approvals, access to the required services at the appropriate cost, and the effectiveness of fracturing technology and applications.

In the NE BC Montney, the contingencies that prevent the Economic Contingent Resources from being classified as reserves are associated with the early evaluation stage of these potential development opportunities. Additional drilling, completion and results are generally required before ARC can commit to their development.

Projects have not been defined to develop the resources in the NE BC Montney as at the evaluation date. Such projects, in the case of the NE BC Montney, have historically been developed sequentially over a number of drilling seasons and are subject to annual budget constraints, ARC's policy of orderly development on a staged basis, the timing of the growth of third party infrastructure, ARC’s short-term and long-term view of natural gas prices, the results of exploration and development activities of ARC and others in the area and infrastructure capacity constraints.

For more information, see "*Risk Factors – Risk Relating to our Business and Operations – There are many uncertainties inherent in estimating quantities of recoverable oil and gas reserves and resources including many factors beyond our control*".

Oil And Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2011.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	3,482	1,626	1,124	165	4,028	1,980	310	58
British Columbia	6	2	5	3	445	220	90	49
Saskatchewan	2,215	849	355	102	5,539	894	86	44
Manitoba	605	148	14	4	-	-	-	-
Total	6,308	2,625	1,498	274	10,012	3,094	486	151

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2011.

	Undeveloped Hectares	
	Gross	Net
Alberta	263,444	177,159
British Columbia	109,233	89,274
Manitoba	3,943	3,642
Saskatchewan	95,705	65,233
Total	472,325	335,308

In the NE BC Montney, we have a total land position of 120,412 gross and 105,672 net hectares which have varying degrees of prospectivity in the Montney zones. For more information, see "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties – Dawson, Parkland-Tower, Montney West, Attachie*". The NE BC Montney has historically been developed sequentially over a number of drilling seasons and is subject to annual budget constraints, ARC's policy of orderly development on a staged basis, the timing of the growth of third party infrastructure, ARC's short-term and long-term view of natural gas prices, the results of exploration and development activities of ARC and others in the area and infrastructure capacity constraints.

We currently have no material work commitments on these lands. There are no material expiries in our core holdings.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used to reduce our exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. We may also potentially be exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio among a number of financially sound counterparties and by monitoring their ongoing credit risks.

In general, under authorities approved by the Board of Directors, management of ARC Resources is permitted to hedge up to a maximum of 55 per cent of forecasted production on a boe basis for up to two years. Management may also use financial instruments to diversify both location and time of sale exposure. In addition to these authorizations to management, the Board of Directors may approve hedging higher percentages of forecasted production or longer term hedging transactions to mitigate risks relating to, and protect the economics of major capital expenditures, including acquisitions.

We have a Risk Committee of the Board of Directors that reviews policies, procedures and provides oversight to management in the areas of financial and business risks including activities related to our hedging program. Our management executes financial hedging transactions to reduce the Corporation's exposure to market price fluctuations either by price protection, through derivatives or swaps, or diversifying its price exposure in accordance with the Board of Directors guidelines or approval on specific transactions.

A summary of financial and physical contracts in respect of hedging activities can be found in Note 16 *"Financial Instruments and Market Risk Management"* to our audited consolidated financial statements for the year ended December 31, 2011 and in the section under the heading *"Risk Management and Hedging Activities"* in our Management's Discussion and Analysis for the year ended December 31, 2011 and 2010 which have been filed on our SEDAR profile at *www.sedar.com*, and both of which note and section are incorporated in this Annual Information Form by reference.

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment and reclamation costs for surface leases, wells, facilities and pipelines which we expect to incur for the periods indicated.

	Abandonment and Reclamation Costs escalated at 2.0% Undiscounted ($MM)	Abandonment and Reclamation Costs escalated at 2.0% Discounted at 10% ($MM)
Total as at December 31, 2011	1,365.7	61.6
Anticipated to be paid in 2012	2.5	2.2
Anticipated to be paid in 2013	2.2	2.0
Anticipated to be paid in 2014	2.3	2.1

We will be liable for our share of ongoing environmental obligations and for the ultimate reclamation of the properties held by us upon abandonment. We estimate that we have an interest in 8,436 net wells that will require abandonment and/or reclamation over the next 61 years with the majority of payments being made in years 2061 to 2072. These ongoing environmental obligations are expected to be funded with funds from operations.

We currently estimate that the future abandonment and reclamation obligations in respect of our properties will be approximately $1,365.7 million calculated by escalating costs at two per cent per year (reflected in our audited consolidated financial statements as an asset retirement obligation of $496.4 million calculated by escalating costs at two per cent per year and discounting at a blended rate of 2.5 per cent). For more information, see Note 14 of our audited consolidated financial statements for the year ended December 31, 2011 and 2010 and the section in our Management's Discussion and Analysis of such financial statements under the heading "*Asset Retirement Obligations and Reclamation Fund*", which note and section are incorporated in this Annual Information Form by reference and are found on SEDAR at *www.sedar.com*. During 2011, $8.4 million ($7.8 million for 2010) of actual expenditures were expended on abandonment and reclamation activities.

We have committed to a restricted reclamation trust associated with the acquisition of the Redwater property pursuant to which ARC Resources has agreed with the vendor of the Redwater property to contribute to such trust certain minimum amounts, totaling approximately $110 million over a 50 year period, to fund future environmental and reclamation obligations in respect of the Redwater properties, or to expend certain minimum amounts towards discharging these obligations. The restricted reclamation trust commenced in 2006 with an initial contribution of $6.1 million. ARC has contributed $33.7 million to the restricted reclamation fund to December 31, 2011. Contributions to the trust will continue at a declining rate through 2055. The balance of the restricted reclamation trust was $26.9 million at December 31, 2011.

We estimate the costs to abandon and reclaim all our shut-in and producing wells, pipelines and facilities. No estimate of salvage value is netted against the estimated cost. Our model for estimating the amount and timing of future abandonment and reclamation expenditures was created on an operating area level. Estimated expenditures for each operating area are benchmarked from numerous sources including the provincial regulatory agencies, industry peer groups, third party engineering firms and actual data from our operations. All wells, pipelines, facilities and associated costs are then assigned to a specific geographic region which is consistent with the methodology used by the Energy Resources Conservation Board.

Abandonment and reclamation costs have been estimated over a 60 year period. Facility abandonment and reclamation costs are scheduled to be incurred in the year following the end of the reserves life of its associated reserve.

Our estimated liability associated with well, pipelines and facilities reclamation costs which were not deducted by GLJ in estimating future net revenue in the GLJ Report are $1,065.7 million (escalating costs at two per cent and undiscounted) and $11.6 million (escalating costs at two per cent and discounted at 10 per cent). Only the abandonment costs associated with wells with reserves were deducted by GLJ in estimating future net revenue.

Tax Horizon

The Corporation expects to allocate its cash flow among funding a portion of capital expenditures, periodic debt repayments, site reclamation expenditures, and cash payments to Shareholders in the form of dividends. Current taxes payable by ARC are subject to normal corporate tax rates. Taxable income varies depending on total income and expenses and varies with changes to commodity prices, costs, claims for both accumulated tax pools and tax pools associated with current year expenditures. ARC has accumulated $2.7 billion of income tax pools for federal tax purposes. Using the current forward commodity price outlook and a modeled future production volume forecast, ARC expects to be in a cash tax-paying position in 2012.

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to our activities for the year ended December 31, 2011:

	2011 $MM
Property acquisition costs[(1)]	
Proved properties	(142.5)
Undeveloped properties	31.2
Exploration costs[(2)]	106.7
Development costs[(3)]	605.8
Corporate capital costs	13.5
Total	614.7

Notes:

(1) Represents acquisition costs net of dispositions and property swaps.

(2) Includes costs of land acquired ($54.4 million), geological and geophysical capital expenditures and drilling costs for 2011 exploration wells drilled.

(3) Includes costs of land acquired ($20.5 million), development and facilities capital expenditures and drilling costs for 2011 development wells drilled.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells that we participated in during the year ended December 31, 2011:

	Exploratory Wells		Development Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Light and Medium Oil	9	8	193	125	202	133
Heavy Oil	-	-	7	-	7	-
Natural Gas	-	-	48	22	48	22
Service	-	-	55	6	55	6
Dry	4	4	9	5	13	9
Total:	13	12	312	158	325	170

For 2012, ARC Resources has planned an extensive capital program of $760 million. The program comprises costs to develop the core assets of the Corporation, including Ante Creek, Pembina, Parkland-Tower, Attachie and the southeast Saskatchewan/Manitoba areas. Our capital program is subject to variation throughout the year depending upon prices for oil and natural gas and there is no assurance that all or any part of our capital program will be expended as planned. In addition, capital expenditures may be made on the acquisition of undeveloped land or oil and natural gas reserves. See "*Risk Factors – Risk Relating to our Business and Operations*".

Production Estimates

The following table sets out the volume of production estimated for the year ended December 31, 2012 which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data*".

	Light and Medium Oil (bbl/d)		Heavy Oil (bbl/d)		Natural Gas (Mcfpd)		Natural Gas Liquids (bbl/d)		Total (boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Total Proved										
Dawson	0	0	0	0	157,828	133,533	781	667	27,085	22,923
Other Properties	26,561	22,710	723	750	166,416	146,612	3,978	3,059	59,000	50,954
Total: Total Proved	26,561	22,710	723	750	324,244	280,145	4,759	3,726	86,085	73,877
Total Proved Plus Probable										
Dawson	0	0	0	0	159,668	135,667	790	678	27,401	23,289
Other Properties	29,558	25,412	738	771	177,785	156,8528	4,476	3,513	64,402	55,837
Total: Total Proved Plus Probable	29,558	25,412	738	771	337,453	292,519	5,266	4,191	91,803	79,126

The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

Production History

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

	Quarter Ended 2011				Year Ended 2011
(6:1)	Mar. 31	June 30	Sept. 30	Dec. 31	
Average Daily Production[1]					
Light and Medium Crude Oil (bbl/d)	27,180	25,174	25,163	27,627	26,284
Heavy Oil (bbl/d)	928	964	861	843	874
Gas (MMcfpd)	246.4	311.8	327.4	355.3	310.6
NGLs (bbl/d)	4,706	4,355	4,593	4,333	4,496
Combined (boe/d)	73,880	82,367	85,178	92,021	83,416
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	82.74	97.75	86.66	93.22	90.05
Heavy Oil ($/bbl)	68.56	78.59	65.87	80.60	73.29
Gas ($/Mcf)	4.05	4.05	3.88	3.43	3.83
NGLs ($/bbl)	61.54	73.61	67.56	76.68	69.68
Combined ($/boe)	48.83	50.02	44.89	45.69	47.24
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	13.28	18.17	14.99	16.30	15.67
Heavy Oil ($/bbl)	7.57	9.20	8.60	8.17	8.37
Gas ($/Mcf)	0.23	0.22	0.36	0.41	0.31
NGLs ($/bbl)	15.81	17.48	18.47	21.58	18.30
Combined ($/boe)	6.81	7.40	6.90	7.60	7.20
Operating Expenses [2][3]					
Light and Medium Crude Oil ($/bbl)	15.71	14.45	16.83	16.13	15.98
Heavy Oil ($/bbl)	16.26	12.18	18.72	20.28	16.80
Gas ($/Mcf)	1.08	1.10	1.16	1.05	1.07
NGLs ($/bbl)	8.79	9.87	10.02	6.28	9.08
Combined ($/boe)	10.12	9.22	10.13	9.40	9.70
Transportation Paid					
Light and Medium Crude Oil ($/bbl)	0.49	0.43	0.75	0.61	0.57
Heavy Oil ($/bbl)	1.41	2.23	1.79	1.74	1.78
Gas ($/Mcf)	0.27	0.29	0.26	0.24	0.26
NGLs ($/bbl)	0.44	0.28	0.30	0.51	0.38
Combined ($/boe)	1.10	1.25	1.24	1.14	1.18

(6:1)	Quarter Ended 2011 Mar. 31	June 30	Sept. 30	Dec. 31	Year Ended 2011
(Loss)/Gain on Commodity Contracts					
Light and Medium Crude Oil ($/bbl)	0.36	(9.62)	2.42	(3.82)	(3.87)
Heavy Oil ($/bbl)	-	-	-	-	-
Gas ($/Mcf)	1.03	0.89	0.89	0.89	0.92
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	3.58	0.44	4.13	2.28	2.18
Netback Received[(4)]					
Light and Medium Crude Oil ($/bbl)	54.62	55.08	56.51	56.36	53.96
Heavy Oil ($/bbl)	43.32	54.98	36.76	50.41	46.34
Gas ($/Mcf)	3.50	3.33	2.99	2.62	3.11
NGLs ($/bbl)	36.50	45.98	38.77	48.31	41.92
Combined ($/boe)	34.38	32.59	30.75	29.83	31.34

Notes:

(1) Before deduction of royalties.

(2) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions have been made in allocating these costs between oil, natural gas and natural gas liquids production.

(3) Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.

(4) Netbacks are calculated by subtracting royalties, operating expenses, transportation costs, and losses/ (gains) on commodity contracts from revenues.

Each of the Dawson, Parkland-Tower, Ante Creek, and Redwater areas account for approximately 27 per cent, 10 per cent, nine per cent and five per cent, respectively, of the total production disclosed above. For more information, see "*Statement of Reserves Data and Other Oil and Gas Information - Other Oil and Gas Information – Principal Properties*".

Marketing Arrangements

Natural Gas

During 2011, we continued our marketing strategy of maintaining a high level of direct control and diversification of marketing and transportation arrangements for our natural gas production.

The average natural gas price we received during 2011 was $3.83 per Mcf before hedging as compared to $4.21 per Mcf before hedging for 2010. This price was achieved with a portfolio mix that on average through the year received AECO index based pricing for 72 per cent, Western Canadian Station 2 index based pricing for 20 per cent, aggregator netback prices for 4 per cent, and Chicago index pricing for 4 per cent of total production.

Our natural gas sales portfolio is directed towards liquid markets and pricing terms that allow us to reduce price volatility and to stabilize the revenue stream. We also strive for a high utilization of contracted pipeline and processing capacity.

Crude Oil and Natural Gas Liquids

Our liquids production in 2011 was comprised of approximately 52 per cent light quality crude oil (greater than 35°API), 31 per cent medium quality crude oil (25 to 35 API), three per cent heavy quality crude (less than 25°API), 14 per cent condensate and natural gas liquids.

During 2011, our average sales prices were $90.05 per bbl for light and medium crude oil, $73.29 per bbl for heavy crude oil and $69.68 per bbl for condensate and natural gas liquids; these prices compare to 2010 prices of $74.33 per bbl for light and medium crude oil, $63.88 per bbl for heavy crude oil and $53.98 per bbl for natural gas liquids.

During the first quarter of 2012, increases in Canadian and United States oil supply, higher than normal refinery outages, and United States pipeline bottlenecks has resulted in significantly lower prices being realized by Canadian producers compared to the WTI price for crude oil. This price decrease has resulted in our inability to realize the full economic potential of its production. For information relating to access to pipelines, see "*Risk Factors – Risk Relating to Our Business and Operations – Gathering and processing facilities and pipeline systems are subject to certain risks and in certain circumstances may adversely affect the amounts realized by us for our oil and natural gas*".

Our crude oil is sold under contracts of varying terms of up to one year, based on market sensitive pricing terms. Natural gas liquids are sold under annual arrangements. Industry pricing benchmarks for crude oil and natural gas liquids are continuously monitored to ensure optimal netbacks.

SHARE CAPITAL OF ARC RESOURCES

The authorized capital of ARC Resources is an unlimited number of Common Shares without nominal or par value (defined in this Annual Information Form as "**Common Shares**") and 50,000,000 preferred shares without nominal or par value issuable in series of which 288,895,582 Common Shares and no preferred shares are outstanding as at December 31, 2011.

The following is a summary of the rights, privileges, restrictions and conditions which attach to the securities of ARC Resources.

Common Shares

Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of the Shareholders of the Corporation (other than meetings of a class or series of shares of the Corporation other than the Common Shares as such).

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

Holders of Common Shares are entitled in the event of any liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its Shareholders for the purpose of winding-up its affairs, and 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 Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

Preferred Shares

Preferred shares may at any time or from time-to-time be issued in one or more series. Before any shares of a particular series are issued, the Board shall, by resolution, fix the number of shares that will form such series and shall, subject to the limitations set out in ARC Resources' articles, by resolution fix the designation, rights, privileges, restrictions and conditions to be attached to the preferred shares of such series, including, but without in any way limiting or restricting the generality of the foregoing, the rate, amount or method of calculation of dividends thereon, the time and place of payment of dividends, the consideration for and the terms and conditions of any purchase for cancellation, retraction or redemption thereof, conversion or exchange rights (if any), and whether into or for securities of ARC Resources or otherwise, voting rights attached thereto (if any), the terms and conditions of any share purchase or retirement plan or sinking fund, and restrictions on the payment of dividends on any shares other than preferred shares or payment in respect of capital on any shares in the capital of ARC Resources or creation or issue of debt or equity securities. Notwithstanding the foregoing, other than in the case of a failure to declare or pay dividends specified in any series of preferred shares, the voting rights attached to the preferred shares shall be limited to one vote per preferred share at any meeting where the preferred shares and Common Shares vote together as a single class.

The preferred shares of ARC Resources are intended to provide future financing flexibility and are not intended to be used to block any takeover bid for ARC Resources. ARC Resources confirms that it will not, without prior shareholder approval, issue any preferred shares for any anti-takeover purpose.

OTHER INFORMATION RELATING TO OUR BUSINESS

Borrowing

We borrow funds from time-to-time to finance the purchase of properties, for capital expenditures or for other financial obligations or expenditures in respect of properties held by us or for working capital purposes. We have a policy relating to borrowing which requires a quarterly assessment by management, subject to review by the Board of Directors of ARC Resources, of the appropriateness of borrowing levels.

Our credit facilities are comprised of both a bank credit facility and long-term notes issued to major financial institutions. We may choose to repay a portion of our debt from one source and borrow from other parties in order to reduce borrowing costs and provide more financial flexibility.

Debt service charges on borrowed funds attributable to our properties, including funds borrowed by our subsidiaries from us, will be deducted in computing income. Debt repayment will be scheduled to the extent possible to minimize any income tax payable by ARC Resources.

As at December 31, 2011, we had credit facilities consisting of a Cdn $1 billion, financial covenant based credit facility with a syndicate of major chartered banks, a Cdn $25 million working capital facility with its agent bank, a Cdn $25 million letter of credit facility with its agent bank, and US $402.0 million and Cdn $29 million of senior notes outstanding. An additional amount of US $118.8 million of senior notes was available to be issued pursuant to a US $225 Master Shelf Agreement with a large insurance company (the "**Master Shelf**"). ARC had a net debt balance of Cdn $909.7 million outstanding at December 31, 2011, comprised of Cdn $761.7 million of long-term debt and a working capital deficit of Cdn $148.0 million.

Borrowings under the syndicated credit facility bear interest at bank prime or, at ARC's option, Canadian dollar bankers' acceptances or U.S. dollar LIBOR loans plus a stamping fee. At the option of ARC, the lenders will review the credit facility each year and determine whether they will extend the revolving four year period for another year. In the event the credit facility is not extended at any time before the maturity date, the loan will become repayable on the maturity date. The maturity date of the current credit facility is August 3, 2015. ARC Resources has the option to draw the remaining credit capacity pursuant to the Master Shelf at any time. This option, currently expires in April 2012, but is in the process of being renewed for an additional three years. ARC Resources may issue senior notes at a rate equal to the related U.S. treasuries corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. The senior notes were issued in eight tranches and bear interest at a fixed rate. Each tranche requires certain repayments of principal prior to the final maturity thereof. The following are significant financial covenants governing the revolving credit facilities:

- Long-term debt and letters of credit not to exceed three times trailing twelve month net income before non-cash items and interest expense;
- Long-term debt, letters of credit and subordinated debt not to exceed four times trailing twelve month net income before non-cash items and interest expense; and
- Long-term debt and letters of credit not to exceed 50 per cent of Shareholders' equity and long-term debt, letters of credit and subordinated debt.

ARC Resources is in compliance in all material respects with the terms of the agreements governing the credit facilities described above.

The credit facilities and senior notes rank equally and contain provisions which restrict the payment of dividends to Shareholders, in the event of the occurrence of certain events of default. The syndicated credit agreement, the note agreements and master shelf agreement are described under "Material Contracts" and have been filed on SEDAR at *www.sedar.com*. For more information, reference is made to Note 13 of our audited consolidated financial statements for the year ended December 31, 2011, which note is incorporated by reference in this Annual Information Form and which has been filed on our SEDAR profile at *www.sedar.com*.

See "*Risk Factors – Risk Relating to Our Business and Operations*".

Dividend Reinvestment and Optional Common Share Purchase Plan

A plan has been established to provide Shareholders who are residents of Canada (within the meaning of the *Tax Act*) with a method to reinvest dividends by purchasing additional Common Shares.

DIRECTORS AND EXECUTIVE OFFICERS

The name and municipality of residence, positions held and principal occupation of each director and officer of ARC Resources as at December 31, 2011 are set out below:

Name and Municipality of Residence	Offices Held and Time as Director	Principal Occupation
Mac H. Van Wielingen [(1)] Calgary, Alberta, Canada	Chairman of the Board and Director since May 3, 1996	Co-Chairman of ARC Financial Corporation (an investment management company)
Walter DeBoni Calgary, Alberta, Canada	Vice Chairman and Director since June 26, 1996	Independent Businessman
John P. Dielwart Calgary, Alberta, Canada	Chief Executive Officer and Director since May 3, 1996	Chief Executive Officer of ARC Resources
Fred J. Dyment Calgary, Alberta, Canada	Director since April 17, 2003	Independent Businessman
Timothy J. Hearn Calgary, Alberta, Canada	Director since June 22, 2011	Independent Businessman
James C. Houck Calgary, Alberta, Canada	Director since February 14, 2008	President and Chief Executive Officer of The Churchill Corporation
Michael M. Kanovsky Calgary, Alberta, Canada	Director since May 3, 1996	Independent Businessman
Harold N. Kvisle Calgary, Alberta Canada	Director since May 20, 2009	Independent Businessman
Kathleen M. O'Neill Toronto, Ontario, Canada	Director since June 1, 2009	Independent Businesswoman
Herbert C. Pinder, Jr. Saskatoon, Saskatchewan, Canada	Director since January 1, 2006	Independent Businessman
Myron M. Stadnyk Calgary, Alberta, Canada	President and Chief Operating Officer	President and Chief Operating Officer of ARC Resources
Steven W. Sinclair Calgary, Alberta, Canada	Senior Vice-President and Chief Financial Officer	Senior Vice-President and Chief Financial Officer of ARC Resources
David P. Carey Calgary, Alberta, Canada	Senior Vice-President, Capital Markets	Senior Vice-President, Capital Markets of ARC Resources
Cameron S. Kramer Calgary, Alberta, Canada	Senior Vice-President, Operations	Senior Vice-President, Operations of ARC Resources

Name and Municipality of Residence	Offices Held and Time as Director	Principal Occupation
Terry Gill Calgary, Alberta, Canada	Senior Vice-President, Corporate Services	Senior Vice-President, Corporate Services of ARC Resources
Terry M. Anderson Calgary, Alberta, Canada	Senior Vice-President, Engineering	Senior Vice-President, Engineering of ARC Resources
P. Van R. Dafoe Calgary, Alberta, Canada	Senior Vice-President, Finance	Senior Vice-President, Finance of ARC Resources
Jay Billesberger Calgary, Alberta, Canada	Vice-President, Information Technology	Vice President, Information Technology of ARC Resources
George Gervais Calgary, Alberta, Canada	Vice-President, Business Development	Vice-President, Business Development of ARC Resources
Neil Groeneveld Calgary, Alberta, Canada	Vice-President, Geosciences	Vice-President, Geosciences of ARC Resources
Wayne Lentz Calgary, Alberta, Canada	Vice-President, Strategic Planning	Vice-President, Strategic Planning of ARC Resources
Al Roberts Calgary, Alberta, Canada	Vice-President, Production	Vice-President, Production of ARC Resources
Allan R. Twa Calgary, Alberta, Canada	Secretary	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)

Notes:

(1) Mr. Van Wielingen is the Chairman and a Director of ARC Resources and was a director of Gauntlet Energy Corporation that secured creditor protection pursuant to the Companies' Creditors Arrangement Act on June 17, 2003 and was subsequently acquired by Ketch Resources Ltd. in December 2003.

(2) The term of each director is until the next annual meeting of ARC Resources, which is scheduled to be held on May 15, 2012.

(3) The following chart sets out the membership of the committees of the Board of Directors as at December 31, 2011.

Name of Director	**Audit Committee**	**Reserves Committee**	**Risk Committee**	**Human Resources & Compensation Committee**	**Policy and Board Governance Committee**	**Health, Safety & Environment Committee**
Independent Outside Directors						
Mac H. Van Wielingen			√	√	√	
Walter DeBoni	√		√		Chair	
Fred J. Dyment	Chair	√	√			
Timothy J. Hearn						
James C. Houck	√	Chair				√
Michael M. Kanovsky		√	Chair		√	
Harold N. Kvisle						Chair
Kathleen M. O'Neill	√			√		
Herbert C. Pinder, Jr.				Chair	√	√

With the exception of the following individuals, the officers and directors have held the position set forth as their principal occupation for the last five years. Prior to February 2009, John P. Dielwart was President and Chief Executive Officer of ARC Resources. Prior to April 2008, Timothy Hearn was Chief Executive Officer and Chairman of Imperial Oil Limited. Prior to October 2007, James Houck was President and Chief Executive Officer and a director of Western Oil Sands Ltd. Prior to July 2010, Harold N. Kvisle was President and Chief Executive Officer of TransCanada Corporation and TransCanada Pipelines Ltd. Prior to February 2009, Myron M. Stadnyk was Senior Vice-President and Chief Operating Officer of ARC Resources. Prior to September 2011, Cameron S. Kramer was Senior Vice-President, North American Operations of Canadian Natural Resources Limited. Prior to

July 2011, Terry M. Anderson was Vice-President, Engineering of ARC Resources and prior to May 2010, was Vice-President, Operations of ARC Resources. Prior to July 2011, P. Van R. Dafoe was Vice-President, Finance of ARC Resources, prior to March 2010, was Vice-President and Treasurer of ARC Resources and prior to July 2007, was Treasurer of ARC Resources. Prior to September 2007, Terry Gill was Senior Vice-President Human Resources at Superior Propane. Prior to July 2011, Jay Billesberger was Manager, Information Technology. Prior to July 2011, George Gervais was Vice-President, Corporate Development of ARC Resources and prior to March 2010, was Manager of Business Development of ARC Resources. Prior to July 2008, Neil Groeneveld was Manager, Geology of ARC Resources. Prior to July 2011, Wayne Lentz was Manager, Strategic Planning of ARC Resources. Prior to September 2011, Al Roberts was Vice-President, Operations of ARC Resources and prior to May 2010, was Manager, Southern Operations of ARC Resources.

The following comprises a brief description of the background of the officers of ARC Resources.

John P. Dielwart, B.Sc., P.Eng.

Mr. Dielwart is the Chief Executive Officer of ARC Resources and has overall management responsibility for ARC Resources. Prior to joining ARC in 1996, Mr. Dielwart spent 12 years with a major Calgary based oil and natural gas engineering consulting firm, as Senior Vice-President and a director, where he gained extensive technical knowledge of oil and natural gas properties in western Canada. Mr. Dielwart holds a Bachelor of Science with Distinction (Civil Engineering) degree, from the University of Calgary. He has been a director of ARC since 1996 and is a Past-Chairman of the Board of Governors for the Canadian Association of Petroleum Producers.

Myron M. Stadnyk, P.Eng.

Mr. Stadnyk is President and Chief Operating Officer of ARC Resources and is responsible for all aspects of ARC's ongoing operational and production management and strategies. He has over 25 years experience in the oil and gas industry. Prior to joining ARC in 1997, Mr. Stadnyk worked with a major oil and gas company in both domestic and international operations. He holds a Bachelor of Science in Mechanical Engineering from the University of Saskatchewan and is a graduate of the Harvard Business School Advanced Management program. Mr. Stadnyk is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, Saskatchewan, Manitoba and British Columbia and currently serves as a governor for the Canadian Association of Petroleum Producers.

Steven W. Sinclair, B. Comm., CA

Mr. Sinclair is Senior Vice-President and Chief Financial Officer of ARC Resources and oversees all of the financial and accounting affairs. He has over 25 years experience within the finance, accounting and taxation areas of the oil and gas industry. Mr. Sinclair joined ARC in 1996. He holds a Bachelor of Commerce from the University of Calgary, and a Chartered Accountant's designation which he received in 1981. Mr. Sinclair is a member of the Alberta and Canadian Institutes of Chartered Accountants.

David P. Carey, P.Eng., MBA

Mr. Carey is Senior Vice-President, Capital Markets of ARC Resources and is responsible for all facets of investor relations and corporate governance. Mr. Carey brings over 25 years of diverse experience in the Canadian and International energy industries covering exploration, production and project evaluations. Prior to joining ARC in 2001, Mr. Carey held senior positions with Athabasca Oil Sands Trust and a major Canadian oil and gas company. He holds both a Bachelor of Science in Geological Engineering and a Master in Business Administration from Queen's University. Mr. Carey is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Cameron S. Kramer, P. Eng.

Mr. Kramer is Senior Vice-President, Operations of ARC Resources and oversees all aspects of ARC's operating activities including both capital execution and field operations. He has over 20 years of experience in the North American oil and gas industry. Prior to joining ARC in 2011, Mr. Kramer worked with a major oil and gas company as Senior Vice-President, North American Operations. Mr. Kramer brings a broad background in operations and leadership. He holds a Bachelor of Science in Chemical and Petroleum Engineering from the University of Calgary and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Terry Gill, B.PE.

Mr. Gill is Senior Vice-President, Corporate Services of ARC Resources and oversees all human resources, information technology and office services related activities. Prior to joining ARC in 2007, Mr. Gill spent eight years with a major national distribution company as a senior executive. He also spent 10 years in the oil and gas industry and has broad experience in all areas of talent management. Mr. Gill holds a Bachelor of Physical Education in Coaching Leadership from the University of Alberta and has coached high performance athletes at an elite level.

Terry M. Anderson, P.Eng.

Mr. Anderson is Senior Vice-President, Engineering of ARC Resources and is responsible for all of ARC's engineering and joint venture related activities. He has over 18 years of experience in operations and engineering. Prior to joining ARC in 2000, he worked at a major oil and gas company. Mr. Anderson holds a Bachelor of Science in Petroleum Engineering from the University of Wyoming. He is a member of the Association of Professional Engineer, Geologists and Geophysicists of Alberta, Saskatchewan and British Columbia.

P. Van R. Dafoe, B. Comm., CMA

Mr. Dafoe is Senior Vice-President, Finance of ARC Resources and is responsible for all of ARC's financial risk management, marketing, tax and treasury related activities. Mr. Dafoe joined ARC in 1999, after 13 years with various companies in the finance and accounting areas of the oil and gas industry. He has a Bachelor of Commerce (Honours) from the University of Manitoba and obtained his Certified Management Accountant's designation in 1995.

Jay Billesberger, B.Sc.

Mr. Billesberger is Vice-President, Information Technology of ARC Resources and is responsible for all Information Technology related activities. Mr. Billesberger has over 14 years of experience in Information Technology. Prior to joining ARC in 2000, he worked with various oil and gas and mid-stream companies. He has a Bachelor of Science in Computer Information Systems from DeVry Institute of Technology.

George Gervais, B.Sc., P.Eng.

Mr. Gervais is Vice-President, Business Development of ARC Resources and is responsible for all of ARC's EOR, acquisition and divestment and land related activities. He brings over 15 years of experience in the oil and gas business covering production, engineering and reserves evaluation. Prior to joining ARC in 2000, Mr. Gervais held a position with a major E&P company. He has a Bachelor of Science in Geological Engineering with Distinction from the University of Saskatchewan. Mr. Gervais is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Neil Groeneveld, M.Sc., P. Geol.

Mr. Groeneveld is Vice-President, Geosciences of ARC Resources and is responsible for the execution of ARC's geophysical and geological activities. He has over 20 years of experience in the western Canadian oil and gas industry and brings a broad background in oil and gas development, exploration and operations. Prior to joining ARC in 2003, Mr. Groeneveld held senior positions with large and intermediate oil and gas companies. He holds a Master of Science in Geology from the University of Regina. Mr. Groeneveld is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Wayne Lentz, P.Eng.

Mr. Lentz is Vice-President, Strategic Planning of ARC Resources and is responsible for ARC's strategic planning and related activities. He brings over 20 years of experience in the oil and gas business covering production, engineering and operations. Prior to joining ARC in 1999, Mr. Lentz worked with a major E&P company in both domestic and international operations. He holds a Bachelor of Science in Petroleum Engineering from the University of Alberta. Mr. Lentz is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Al Roberts

Mr. Roberts is Vice-President, Production of ARC Resources and manages all aspects of field production operations and health, safety and environment. He has over 30 years of broad experience across the western Canadian sedimentary basin in production operations, completions and facilities construction. Prior to joining ARC in 1997, Mr. Roberts spent 18 years managing field operations for both junior and intermediate producers.

Allan R. Twa, Q.C.

Mr. Twa acts as Corporate Secretary of ARC Resources. A member of the Alberta Bar since 1971, Mr. Twa is a partner in the law firm Burnet, Duckworth & Palmer LLP. Mr. Twa holds a B.A. (Political Science) from the University of Calgary, a LL.B. from the University of Alberta and a LL.M. from the University of London, England. Over the last 35 years, Mr. Twa has been engaged in a legal practice involving legal administration of public companies and trusts, corporate finance, and mergers and acquisitions.

All of the directors of ARC Resources other than Timothy J. Hearn were elected as directors of ARC Resources Ltd. on May 18, 2011 to hold office until the next annual meeting of ARC Resources, which is scheduled to be held on May 15, 2012. Mr. Hearn was appointed as a director of ARC Resources on June 22, 2011. As at December 31, 2011, the directors and officers of ARC Resources, as a group, beneficially owned, or controlled or directed, directly or indirectly, 2,623,049 Common Shares or approximately 0.9 per cent of the outstanding Common Shares.

AUDIT COMMITTEE DISCLOSURES

Multilateral Instrument 52-110 ("**MI 52-110**") relating to audit committees has mandated certain disclosures for inclusion in this Annual Information Form. The text of the Audit Committee's mandate is attached as Appendix C to this Annual Information Form.

Members of the Audit Committee

As of December 31, 2011, the members of the Audit Committee were Fred J. Dyment, chairman, Walter DeBoni, James C. Houck and Kathleen O'Neill, each of whom is independent and financially literate within the meaning of MI 52-110. The following comprises a brief summary of each member's education and experience:

Fred J. Dyment

Mr. Dyment has over thirty years of extensive experience in the oil and gas industry and is currently an independent businessman. He has held positions as President and Chief Executive Officer for Maxx Petroleum and President and Chief Executive Officer of Ranger Oil Limited. Mr. Dyment received a Chartered Accountant designation from the province of Ontario in 1972. Currently, he serves on the board of directors for Tesco Corporation, Transglobe Energy Corporation, Major Drilling Group International and WesternZagros Resources Ltd. Mr. Dyment has been a director of ARC since 2003.

Walter DeBoni

Mr. DeBoni is a Corporate Director and has extensive experience in the oil and gas industry. Mr. DeBoni retired from Husky Energy Inc. in 2005, where he held the position of Vice-President, Canada Frontier and International Business. Prior thereto, he was the Chief Executive Officer of Bow Valley Energy. In addition to his time at Husky and Bow Valley he has held numerous top executive posts in the oil and gas industry with major corporations. Mr.

DeBoni holds a Bachelor of Science in Chemical Engineering from the University of British Columbia and a Masters in Business Administration with a major in Finance from the University of Calgary. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Society of Petroleum Engineers. He currently serves on the board of directors for Sterling Resources Ltd. Mr. DeBoni has been a director of ARC Resources since 1996.

James C. Houck

Mr. Houck is President and Chief Executive Officer of the Churchill Corporation, a diversified construction company. Previously, he was President and Chief Executive Officer of Western Oil Sands. The greater part of his career was spent with ChevronTexaco Inc., where he held a number of senior management and officer positions, including President, Worldwide Power and Gasification Inc., and Vice-President and General Manager, Alternate Energy Department. Earlier in his career, Mr. Houck held various positions of increasing responsibility in Texaco's conventional oil and gas operations. Mr. Houck has a Bachelor of Engineering Science degree from Trinity University in San Antonio and a Masters in Business Administration degree from the University of Houston. Currently, he serves on the board of directors for the Churchill Corporation and WesternZagros Resources Ltd. Mr. Houck has been a director of ARC since 2008.

Kathleen M. O'Neill

Ms. O'Neill is a Corporate Director and has extensive experience in accounting and financial services. Previously, she was an Executive Vice-President of Bank of Montreal Financial Group with accountability for a number of major business units. Prior to joining the Bank of Montreal Financial Group in 1994, she was a partner with PricewaterhouseCoopers. Ms. O'Neill is an FCA (Fellow of Institute of Chartered Accountants) and has an ICD.D designation from the Institute of Corporate Directors. She currently serves on the board of directors of Invesco Canada Funds, Finning International Inc., and the TMX Group Inc. Ms. O'Neill has been a director of ARC since 2009.

Principal Accountant Fees and Services

The Audit Committee has not adopted specific policies and procedures for the engagement of non-audit services and pre-approves each such engagement or type of engagement for every fiscal year.

Our external auditor is Deloitte & Touche LLP. The following is a summary of the external audit services fees by category.

	2011	**2010**
Audit Fees	$982,478	$684,133
Audit Related Fees(1)	$69,892	$167,722
Tax Fees(2)	$0	$0
All Other Fees	$16,241	$0

Notes:

(1) The aggregate fees billed by our external auditor for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements but which are not included in audit services fees.

(2) The aggregate fees billed by our external auditor for professional services for municipal property tax compliance, tax advice and tax planning.

CONFLICTS OF INTEREST

The Board of Directors has adopted a Code of Business Conduct and Ethics and a Code of Ethics for Senior Financial Officers (the "**Codes**"). In general, the private investment activities of employees, directors and officers are not prohibited, however, should an existing investment pose a potential conflict of interest, the potential conflict is required by the Codes to be disclosed to the Chief Executive Officer, President or the Board of Directors. Any other activities of employees which pose a potential conflict of interest are also required by the Codes to be disclosed to the Chief Executive Officer, President or the Board of Directors. Any such potential conflicts of interests will be dealt with openly with full disclosure of the nature and extent of the potential conflicts of interests with the Corporation.

It is acknowledged in the Codes that employees, officers and directors may be directors or officers of other entities engaged in the oil and gas business, and that such entities may compete directly or indirectly with the Corporation. No assurance can be given that opportunities identified by directors of ARC Resources will be provided to us. Passive investments in public or private entities of less than 1 per cent of the outstanding shares will not be viewed as "competing" with the Corporation. Any director, officer or employee of ARC Resources which is a director or officer of any entity engaged in the oil and gas business shall disclose such occurrence to the Board of Directors. Any director, officer or employee of ARC Resources who is actively engaged in the management of, or who owns an investment of 1 per cent or more of the outstanding shares, in public or private entities shall disclose such holding to the Board of Directors. In the event that any circumstance should arise as a result of such positions or investments being held or otherwise which in the opinion of the Board of Directors constitutes a conflict of interest which reasonably affects such person's ability to act with a view to the best interests of the Corporation, the Board of Directors will take such actions as are reasonably required to resolve such matters with a view to the best interests of the Corporation. Such actions, without limitation, may include excluding such directors, officers or employees from certain information or activities of the Corporation.

The *Business Corporations Act* (Alberta) provides that in the event that an officer or director is a party to, or is a director or an officer of or has a material interest in any person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any director or senior officer, or to our knowledge any person or company that is the direct or beneficial owner, or who exercises control or direction over more than 10 per cent of outstanding Common Shares, or any associate or affiliate of any of the foregoing, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to affect the Corporation.

DIVIDENDS AND DISTRIBUTIONS

Dividend Policy

In conjunction with the completion of the Trust Conversion, the Board of Directors of ARC Resources established a dividend policy of paying monthly dividends to holders of Common Shares, initially set at $0.10 per Common Share, which will be paid to Shareholders of record on or about the 15th day of each month. In general, the Board of Directors attempts to set the dividend amount at a level which at that time appears sustainable for a minimum period of six months. The payment of dividends by the Corporation commenced with a dividend declared to Shareholders of record on January 31, 2011 in the amount of $0.10 per Common Shares made payable on February 15, 2011.

It is expected that the dividends declared and paid will be "eligible dividends" for income tax purposes and thus qualify for the enhanced gross-up and tax credit regime available to certain holders of Common Shares. Although it is expected that dividends of ARC Resources will qualify as "eligible dividends" for the purposes of the Tax Act, and thus qualify for the enhanced gross-up and tax credit regime available to certain holders of Common Shares, no assurances can be given that all dividends will be designated as "eligible dividends" or qualify as "eligible dividends".

Notwithstanding the foregoing, the amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors of ARC Resources and may vary depending on a variety of factors and conditions existing from time-to-time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends.

For information relating to risks relating to dividends, see "*Risk Factors - Risk Relating to Our Business and Operations– The Board of Directors has discretion in the payment of dividends and may not chose to maintain the payment of dividends in certain circumstances*".

In certain circumstances, the payment of dividends may be restricted by our borrowing agreements. For more information see "*Other Information Relating to Our Business – Borrowing*".

Dividend History

The following per Common Share dividends (Trust Unit distributions prior to the completion of the Trust Conversion) were made in the last three completed financial years of ARC:

2009	
First Quarter	$0.36
Second Quarter	$0.32
Third Quarter	$0.30
Fourth Quarter	$0.30
2010	
First Quarter	$0.30
Second Quarter	$0.30
Third Quarter	$0.30
Fourth Quarter	$0.30
2011	
First Quarter	$0.30
Second Quarter	$0.30
Third Quarter	$0.30
Fourth Quarter	$0.30

Dividends paid to Shareholders (distributions paid to Unitholders prior to the completion of the Trust Conversion) in 2009 were 3 per cent tax deferred and in 2010 were 14 per cent tax deferred.

MARKET FOR SECURITIES

Common Shares

The Common Shares commenced trading on the TSX on January 6, 2011 following the completion of the Trust Conversion. The trading symbol for the Common Shares is ARX.

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Common Shares (Trust Units prior to January 6, 2011) on the TSX for the periods indicated (as quoted by the TSX):

	Toronto Stock Exchange		
2011 Period	**High** **$**	**Low** **$**	**Volume**
January	25.67	24.05	1,690,882
February	28.40	24.80	2,002,729
March	27.70	25.80	1,284,787
April	26.50	24.20	961,949
May	26.79	23.89	921,967
June	26.13	24.50	1,111,682
July	26.10	23.75	919,642
August	24.50	21.03	1,140,491
September	24.66	20.87	1,253,797
October	25.82	19.85	1,264,479
November	25.86	23.72	1,178,314
December	26.60	24.41	1,367,304

Series A Exchangeable Shares

Prior to the completion of the Trust Conversation, the series A exchangeable shares of ARC Resources Ltd. were listed and posted for trading on the TSX. The trading symbol for the series A exchangeable shares of ARC

Resources Ltd. was ARX.A (ARX prior to October 18, 2010). The ARX.A exchangeable shares were delisted on January 6, 2011. For the period January 1, 2011 through January 5, 2011, there was no trading activity for the series A exchangeable shares on the TSX.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, Saskatchewan and Manitoba, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

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

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, 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 pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

On October 25, 2007, the Government of Alberta released a report entitled "The Alberta Royalty Framework" ("**NRF**") containing proposals which were subsequently implemented by the *Mines and Minerals (Alberta Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. Changes in Alberta's royalty system in effect after December 31, 2011 are known as the "Alberta Royal Framework" (the "**ARF**").

Under the ARF, 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. Effective January 1, 2011, the maximum royalty payable under the ARF was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/m^3 compared to the previous royalty curve.

Royalty rates for natural gas under the ARF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the ARF was set at 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the "**IETP**"), which has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the ARF 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 a $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 May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spud subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 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 5-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 deep oil wells (between 1,000 and 3,500 m) 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 ARF. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the ARF. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

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. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" was reached. The New Well Royalty Regulation, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

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

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

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

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

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

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

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

- *Marginal Royalty Reduction Program* providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

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

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

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In 2009, 2010 and 2011, the Government of British Columbia awarded $120 million in royalty credits to oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

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

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

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* replacing the existing *Freehold Oil and Gas Production Tax Act* with the intention of facilitating more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new legislation, although several regulations remain in force under the previous legislation.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas.

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

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

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

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

- *Royalty Tax Regime for High Water-Cut Oil Wells* granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

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

Manitoba

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

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

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

The Government of Manitoba maintains a Drilling Incentive Program (the "Program") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no Crown royalties or freehold production taxes are payable until the holiday oil volume has been produced. Holiday oil volumes must be produced within ten (10) years of the finished drilling date or the completion date of a major workover. Wells drilled for injection, or converted to injection wells, in an approved enhanced recovery project, earn one (1) year holiday for portions of the project area. Under the Program, wells drilled for purposes of injection (or wells converted to injection prior to producing predetermined volumes of oil) in an approved enhanced oil recovery project earn a one-year holiday for portions of the project area.

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

- *New Well Incentive* provides licensees of newly drilled, non-horizontal wells drilled prior to January 1, 2014 with a holiday oil volume to a maximum of 10,000 m3;

- *Deep Drilling Incentive* provides licensees who drill a well to a total depth sufficient to penetrate the Devonian Duperow formation with a holiday oil volume of up to 20,000 m3, and licensees who drill a well deeper than the Devonian Three Forks formation can make a one-time assignment of up to 10,000 m3 of holiday oil volume earned through previous drilling or major workovers to such well's holiday oil volume;

- *Horizontal Well Initiative* provides licensees of horizontal wells drilled prior to January 1, 2014 with a holiday oil volume of 10,000 m3, and the first horizontal leg (unless otherwise approved) drilled from an existing horizontal well on or after January 1, 2009 and prior to January 1, 2014 and more than one (1) year after the finished drilling date of the well), will earn an additional holiday royalty volume of 3,000 m3;

- *Marginal Well Major Workover Incentive* provides licensees of marginal wells where a major workover is completed prior to January 1, 2014 with a holiday oil volume of 500 m3, with a marginal oil well defined as an abandoned well or a well that was either not operated over the previous 12 months or produced oil at an average rate of less than 1 m3 per operating day; and

- *Injection Well Incentive* provides a one year exemption from the payment of Crown royalties or freehold production taxes on production allocated to a unit tract in which a well is drilled or converted to water injection.

Further, holiday oil volumes earned by a newly drilled well or a marginal well that has undergone a major workover can be transferred to a Holiday Oil Volume Account at the request of the licensee, the purpose of which is to optimize the value of holiday oil volumes earned by providing a company with the flexibility of allocating holiday oil volumes earned among new wells.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments with the exception of Manitoba where approximately 80% of crude oil and natural gas rights in the southwestern portion of the province are privately owned. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Rights to explore for and produce oil and natural gas from privately held lands are granted by lease on such terms and conditions as may be negotiated.

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

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licences issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease and the intermediate term of the license. 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. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion; 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. The order in which these agreements will receive reversion notices will depend on their vintage and location and the Government of Alberta had anticipated that the receipt of reversion notices for older leases would commence in April 2011; however, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in spring 2012.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time-to-time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

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

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

On August 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the "**Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

Climate Change Regulation

Federal

The Government of Canada has initiated its plan to regulate Greenhouse Gas (“**GHG**”) emissions from large industrial emitters through performance standards. The first sector to be regulated is coal-fired electricity generators, followed by the oil and gas sector. The Government of Canada has released draft regulations for performance standards on new coal-fired electricity generation units and facilities which have reached the end of their useful life. Final regulations have not been published.

This regulatory step is a significant sign regarding how Canada aims to define its climate change strategy. While the Government of Canada is pursuing a reduction in industrial GHGs, it has been clear that there is no intention to implement carbon pricing, such as a carbon tax or cap-and-trade.

In January 2012, the Government of Canada announced flexibility will be introduced into the regulations for coal-fired plants. While not finalized, it is expected that provinces will be responsible for implementation, instead of the Government of Canada. The new approach will allow the provinces to set overall emissions targets, rather than accept specific targets for each individual facility as proposed in the original federal approach. Flexibility mechanisms are also being discussed, such as amending the timelines for required emissions reductions.

The Government of Canada is currently consulting with oil and gas representatives to extend performance standards to the sector. Consultations have been reasonably collaborative. In designing the regulations, three working groups have been established: oil sands, upgraders and refineries, and 'other.' A late 2012 release was anticipated, but no release is expected until the coal-fired generation regulations are finalized.

The 17th Conference of the Parties ("**COP 17**"), in December 2011, resulted in the Durban Platform for Enhanced Action. The Platform compels signatories to develop a legally binding GHG reduction accord before 2015, to come into force before 2020. Additional outcomes from COP 17 include continued development of the Green Climate Fund and the design of procedures for carbon capture and storage as a potential offset type under the Clean Development Mechanism. This is a major accomplishment which may lead to carbon capture and storage being leveraged under other carbon markets.

The Durban agreement's inclusion of developing counties captures major emitters like India and China. Many have identified this development as critical to the future of the United Nations Framework Convention on Climate Change **("UNFCCC")** process.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, 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 and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs per year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains several compliance mechanisms. 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, they can reduce their emissions through in-house reductions, or they can purchase emissions credits from regulated emitters that have reduced their emissions below their emission intensity target 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. As a non-regulated entity, ARC is able to consider engaging in the Alberta carbon offset market as a net-seller of offsets in accordance with the CCEMA.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or combustion of virtually all fossil fuels purchased or used in British Columbia. The current level of the tax is $25 per tonne of CO2 equivalent. It is scheduled to increase to $30 per tonne of CO2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the Greenhouse Gas Reduction (Cap and Trade) Act (the "Cap and Trade Act") which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents (CO_2e) per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2e per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed emissions trading are currently under development.

The Greenhouse Gas Reduction Targets Act (GGRTA) was legislated in 2007 and requires British Columbia's GHG emissions to be reduced by at least 33 per cent below 2007 levels by 2020. The Act provides authority for the Emission Offsets Regulation and the Carbon Neutral Government Regulation (both enacted in 2008).

ARC is subject to the reporting and verification requirements for its operations throughout the province. We are actively exploring carbon offset opportunities available under the Emission Offset Regulation.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to the Alberta climate change initiative. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions, or some combination of an absolute cap and emissions intensity.

Manitoba

The Government of Manitoba has indicated its intention to commence public consultations with respect to the development of a cap and trade system to reduce GHG emissions; however, no legislation with respect to the same is currently in effect in Manitoba.

RISK FACTORS

The following is a summary of certain risk factors relating to our business which prospective investors should carefully consider before deciding whether to purchase Common Shares. Residents of the United States and other non-residents of Canada should have additional regard to the risk factors under the heading "Risk Factors Applicable to Residents of the United States and Other Non-Residents of Canada".

Our income and cash flow is derived from the production of oil and natural gas from our Canadian resource properties and is susceptible to the risks and uncertainties associated with the oil and natural gas industry generally, including those risks set forth below. If the oil and natural gas reserves associated with our resource properties are not supplemented through additional development or the acquisition of additional oil and natural gas properties, our ability to pay dividends to Shareholders may be adversely affected. The price at which the Common Shares trade is dependent on a variety of economic, political and regulatory factors many of which are beyond our control and only, in part, on our ability to manage the risks set forth below, some of which are beyond our control.

Risk Relating to Our Business and Operations

Declines in oil and natural gas prices will adversely affect our financial condition

Our operational results and financial condition, and therefore the amounts we pay to Shareholders as dividends, will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have exhibited extreme volatility over the past few years. The price of crude oil averaged WTI $94.04 per bbl for the year ended December 31, 2011 as opposed to $81.87 per bbl for the year ended December 31, 2010. The price of AECO natural gas for the year ended December 31, 2011 was $3.67 per Mcf as opposed to $4.12 per Mcf for the year ended December 31, 2010 and has declined significantly again in early 2012 averaging $2.45 per Mcf in February. Natural gas inventories in North America are at record highs and, in conjunction with declining prices, could result in the shut-in of natural gas production in 2012 and beyond. Declines in oil and natural gas prices may result in declines in, or elimination of, dividends paid on the Common Shares. Oil and natural gas prices are determined by economic factors and in the case of oil prices, political factors and a variety of additional factors beyond our control. These factors include economic conditions, in the United States, Canada, Europe and worldwide, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, internal capacity to produce natural gas in the United States from shale deposits, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Ongoing political unrest in the countries of North Africa and the Middle East may create more volatility in the price of oil and may threaten the ongoing recovery of the global economy or may have other unforeseen consequences. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our proved and probable reserves, net asset value, borrowing capacity, production, revenues, profitability and cash flows from operating activities, levels of capital expenditures and ultimately on our financial condition and therefore on the dividends to be paid to our Shareholders.

Gathering and processing facilities and pipeline systems are subject to certain risks and in certain circumstances may adversely affect the amounts realized by us for our oil and natural gas

The Corporation delivers its products through gathering, processing and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. During the first quarter of 2012, increases in Canadian and United States oil supply, higher than normal refinery outages, and United States pipeline bottlenecks has resulted in significantly lower prices being realized by Canadian producers compared to the WTI price for crude oil. This price decrease could result in the Corporations inability to realize the full economic potential of its production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

Certain pipeline leaks in 2011 have gained media and other stakeholder attention and may result in additional regulation or changes in law which could impede ARC's conduct of its business or make its operations more expensive.

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

Increases in the value of the Canadian dollar against the U.S. dollar will adversely affect our financial condition

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 negatively impacts our production revenue and our ability to maintain funds from operations and future dividends.

The global economy has not fully recovered and unforeseen events may negatively impact our financial condition

Market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility to commodity prices over the last few years. These conditions have caused a loss of confidence in the global credit and financial markets and created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms and may make it more difficult to operate effectively.

The Board of ARC Resources has discretion in the payment of dividends and may not choose to maintain the payment of dividends in certain circumstances

Monthly distributions reached a high point of $0.28 per Trust Unit, in August of 2008 and declined to $0.10 per Trust Unit in 2009 and have been maintained at the current monthly dividend of $0.10 per Common Share. Dividends on the Common Shares are not preferential, nor cumulative nor stipulated by their terms to be at a fixed amount or rate. As such dividends do not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed yield securities, where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments. Dividends are conditionally declared by our Board in its sole discretion and are subject to confirmation by a monthly press release and are specifically subject to change in accordance with the dividend policy of ARC. The dividend policy is also subject to change in the sole discretion of ARC. See "*Dividends and Distributions – Dividend Policy*". Dividends may be varied or discontinued at any time.

Our ability to maintain dividend payments is dependent on a number of factors including our success in exploiting existing properties and acquiring additional reserves

Our ability to add to our oil and natural gas reserves is highly dependent on our success in exploiting existing properties and acquiring additional reserves. We currently distribute a proportion of our cash flow from operating activities, by way of dividend payments, to Shareholders rather than reinvesting it in reserves additions. Our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves is dependent on external sources of capital and maintenance of our cash flow from operating activities. To the extent that we use cash flow from operating activities to finance capital expenditures or property acquisitions, the level of cash flow from operating activities available for the payment of dividends to Shareholders will be reduced. There is no assurance we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserves additions, our reserves will deplete and as a consequence, either production from, or the average reserves life of, our properties will decline, which will result in a reduction in the value of Common Shares and in a reduction in cash flow from operating activities available for the payment of dividends to Shareholders.

Our hedging activities may negatively impact our income and the financial condition of the Corporation.

We actively manage the risk associated with changes in commodity prices by entering into oil or natural gas price hedges. If we hedge our commodity price exposure, we will forego some of the benefits we would otherwise experience if commodity prices were to increase, and some of these foregone benefits may be material. For more information in relation to our commodity hedging program, see "*Statement of Reserve Data and Other Oil and Gas Information – Other Oil and Gas Information – Forward Contracts*". We may initiate certain hedges to attempt to mitigate the risk of the Canadian dollar appreciating against the U.S. dollar. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates may impact future funds from operations, dividend payments and the future value of our reserves as determined by independent evaluators. These hedging activities could expose us to losses, which may be material, and to credit risk associated with counterparties with which we contract.

Our business is heavily regulated including through the payment of royalties and such regulation increases our costs and may adversely affect our financial condition

Oil and natural gas operations (including land tenure, exploration, development, production, refining, transportation and marketing) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time-to-time. In particular, most of our oil and natural gas assets are subject to royalties imposed by the governments of British Columbia, Alberta, Saskatchewan and Manitoba which are subject to variation by such governments. Governments may regulate or intervene with respect to exploration and production activities, price, taxes, royalties and the exportation of oil and natural gas. Regulation increases our costs. In order to conduct oil and gas operations, we require licenses from various governmental authorities. There can be no assurance that we will be able to obtain all of the licenses and permits that may be required to conduct operations that we may wish to undertake. See "*Industry Conditions*".

Our oil and natural gas reserves are a depleting resource and decline as such reserves are produced

The payment of dividends out of cash flow generated from properties, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. Our future oil and natural gas reserves and production, and therefore our cash flows from operating activities, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, our reserves and production may decline over time as reserves are produced. There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

Our success depends in large measure on certain key personnel and our ability to retain our key personnel

The loss of such key personnel could delay the completion of certain projects or otherwise have a material adverse effect on us. Shareholders will be dependent on our management in respect of the administration and management of all matters relating to our properties, the Common Shares and the safekeeping of our primary workspace and computer systems. Any deterioration of our corporate culture could adversely affect our long-term success. As of December 31, 2011, we operated approximately 87% of the total daily production of our properties.

Our bank credit facility is subject to a four year term and a fixed amount

We currently have a $1 billion syndicated credit facility with thirteen banks of which we had drawn $319.9 million as at December 31, 2011. The maturity date of the facility is August 3, 2015. The terms of the credit facility allow renewals yearly at the request of ARC and at the discretion of the lenders in order to enable us to maintain a four year term.

We had U.S. $402.1 million of U.S. denominated and Cdn $29 million of long-term debt outstanding in the form of Long-Term Notes ("**Notes**") as at December 31, 2011. The next scheduled principal repayment of the Notes is in April 2011 and the final scheduled principal repayment is in May 2022. We intend to fund these repayments with existing credit facilities and/or with proceeds from additional note issuances.

We are required to comply with covenants under the credit facility and under our U.S. and Canadian denominated long-term notes. In the event that we do not comply with covenants under the credit facility and our long-term notes, our access to capital could be restricted or repayment could be required on an accelerated basis by our lenders, and the ability to pay dividends to our Shareholders may be restricted.

Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service resulting in a decrease in the amount available for payment of dividends on the Common Shares. Certain covenants of the agreements with our lenders may also limit the payment of dividends. Although we believe the credit facilities will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations including our future capital expenditure programs, or that additional funds will be able to be obtained.

For more information, see "*Other Information Relating to Our Business – Borrowing*".

We have been historically reliant on external sources of capital, borrowings and equity sales, and if unavailable, our financial condition could be adversely affected

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operating activities, borrowings, property dispositions and possible future equity sales, our ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and our securities in particular. Further, if our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs.

As a result of global economic volatility, the Corporation, along with many other oil and gas entities, may, from time-to-time, have restricted access to capital and increased borrowing costs.

Alternatively, we may issue additional Common Shares from treasury at prices which may result in a decline in production per Common Share and reserves per Common Share or we may wish to borrow to finance significant acquisitions or development projects to accomplish our long-term objectives on less than optimal terms or in excess of our optimal capital structure.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain or expand existing assets and reserves may be impaired, and our assets, liabilities, business, financial condition, results of operations and dividend payments may be materially and adversely affected as a result.

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

Failure of third parties to meet their contractual obligations to us may have a material adverse effect on our financial condition

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, third party operators, marketers of our petroleum and natural gas production and other parties. Poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

Income tax laws, or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia, Saskatchewan and Manitoba, all of which should be carefully considered by investors in the oil and gas industry. All of such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse and there can be no assurance that there will not be further revocation, amendment or administrative change which will be materially adverse to our assets, reserves, financial condition or results of operations or prospects and our ability to maintain the payment of dividends.

Tax authorities having jurisdiction over us or Shareholders may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment or the detriment of Shareholders.

There are numerous uncertainties inherent in estimating quantities of recoverable oil and natural gas reserves and resources including many factors beyond our control

In general, estimates of economically recoverable oil and natural gas reserves and resources, the future net revenues and finding and development costs are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results.

The reserves and recovery information and the resource information contained in the GLJ Report is only an estimate and the actual production and ultimate reserves and resources from the properties may be greater or less than the estimates prepared by GLJ. The GLJ Report has been prepared using certain commodity price assumptions which are described in the notes to the reserves tables. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the price assumptions utilized in those reserves reports, the present value of estimated future net revenues for our reserves and net asset value would be reduced and the reduction could be significant. The estimates in the GLJ Report are based in part on the timing and success of activities we intend to undertake in future years. The reserves and estimated future net revenues contained in the GLJ Report will be reduced in future years to the extent that such activities do not achieve the production performance set forth in the GLJ Report.

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

Estimates of Economic Contingent Resources contained in the GLJ Report are subject to the definitions, disclaimers, contingencies and warnings set forth under the heading "Statement of Reserves Data and Other Oil and Gas Information – Contingent Resource Estimates". There is no certainty that it will be commercially viable to produce any portion of the resources.

Increases in interest rates may adversely affect our financial condition

There is a risk that interest rates will increase given the current historical low level. An increase in interest rates would result in an increase in the amount we pay to service debt, resulting in a decrease in funds from operations. This could affect dividends to shareholders and the market price of the common shares.

Hydraulic fracturing is subject to certain risks

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (natural gas and oil) production. The use of hydraulic fracturing is being used to produce commercial quantities of natural gas and oil from reservoirs that were previously unproductive. We use hydraulic fracturing extensively in our operations. With the increase in the use of fracture stimulations in horizontal wells there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology as it relates to the environment. This increased attention to fracture stimulations may result in increased regulation or changes of law which may make the conduct of our business more expensive or prevent us from conducting our business as currently conducted. Any new laws, regulation or permitting requirements regarding hydraulic fracturing could lead to operational delay or increased operating costs or third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves and could materially reduce both the volume and the value of our reserves.

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome

These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires, spills and delays in payments between parties caused by operation or economic matters. These risks will increase as we undertake more exploratory activity. Drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Continuing production from a property, and to some extent the marketing of production, are largely dependent upon the ability of the operator of the property. Other companies operate some of the properties in which we have an interest and as a result our returns on assets operated by others depends upon a number of factors outside our control. To the extent the operator fails to perform these functions properly, operating income may be reduced.

Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects and our ability to maintain the payment of dividends.

Our future enhanced operated opportunities may not be economically or technically feasible

We believe our ownership of assets in Redwater and North Pembina Cardium Unit #1 strategically positions us for participation in properties with large unrecovered original resources in place which may be amenable to secondary recovery techniques such as CO_2 miscible or immiscible flooding. The implementation of enhanced oil recovery techniques on properties like Redwater or the North Pembina Cardium Unit #1 are subject to significant risk factors, including the requirements of successful results from field pilot programs, long-term supply agreements for CO_2 and large scale infrastructure investments. We have just begun to devote resources to the study of such matters and no reserves are reflected in the GLJ Report for any of these enhanced recovery techniques for the two subject properties. In order for ARC Resources to carry out its enhanced oil recovery program it is necessary to obtain large volumes of CO_2 at a cost effective rate which requires infrastructure to be put in place to facilitate this process. Under the current regulatory environment, the economic parameters of the Corporation's enhanced oil recovery programs would be limited. There is no assurance as to when or if such enhanced recovery techniques will be implemented, or if implemented, when or if such enhanced recovery techniques would be successful.

We are participating in larger projects and have more concentrated risk in certain areas of our operations

We manage a variety of small and large projects in the conduct of our business. We have undertaken large development projects, including the construction of gas processing plants, in northeastern British Columbia for the development of our natural gas reserves. Project delays may impact expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

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

Because of these factors, we could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that we produce.

We only operate in western Canada and expansion outside of these areas may increase our risk exposure

Our operations and expertise are currently focused on oil and gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire oil and gas properties outside this geographic area. In addition, we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines, or an interest in an oil sands project. Expansion of our activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors which may adversely affect our future operational and financial conditions.

We may not be able to realize the anticipated benefits of acquisitions and dispositions

The price we pay for the purchase of any material properties is based on engineering and economic estimates of the reserves made by management and independent engineers modified to reflect our technical and economic views. These assessments include a number of material factors and assumptions. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flow from operating activities and the payment of dividends to Shareholders. See "*ARC Resources Ltd. – General Development of the Business*".

We make acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. There is no assurance that we will be able to continue to complete acquisitions or dispositions of oil and natural gas properties which realize all the synergistic benefits expected.

Climate change laws and related environment regulation may impose restrictions or impose costs on our business which may adversely affect our financial condition and our ability to maintain distributions

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of us or our properties, some of which may be material. Furthermore, management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which we cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions – Climate Change Regulation*".

There has been much public debate with respect to the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies by either the provinces in which we operate our business or by the Government of Canada, and whether to meet international agreed limits, or as otherwise determined, for reducing greenhouse gases could have a material impact on the nature of oil and natural gas operations, including ours. 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 either the nature of those requirements or the impact on us and our operations and financial condition. We have established a reclamation fund for the purpose of funding our currently estimated future environmental and reclamation obligations for our assets at Redwater. We have not established a reclamation fund for any of our other assets. There can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations for our assets at Redwater or elsewhere.

Although we believe that we are in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect our financial condition, results of operations or prospects. Future changes in other environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition or results of operations and prospects. See "*Industry Conditions – Climate Change Regulation*".

There is strong competition relating to all aspects of the oil and gas industry

There are numerous companies in the oil and gas industry, who are competing with us for the acquisitions of properties, properties with exploitation and development opportunities and undeveloped land. As a result of such competition, it may be more difficult for us to acquire reserves on beneficial terms. Many of these other oil and gas companies have significantly greater financial and other resources than we do.

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

We compete with other oil and gas entities to hire and retain skilled personnel necessary for our daily operations including planning, realizing on available technical advances and the execution of the annual capital development program. The inability to hire and retain skilled personnel could adversely impact certain of our operational and financial results.

Application of International Financial Reporting Standards may result in non-cash losses which may adversely affect the market price of our Common shares

Effective January 1, 2011, all Canadian publicly accountable enterprises were required to apply International Financial Reporting Standards ("IFRS"). IFRS may result in non-cash charges and/or write-downs of net assets in the financial statements. Such non-cash charges and write-downs under IFRS may be viewed unfavourably by the market and may result in an inability to borrow funds and/or may result in a decline in the price of the Common Shares.

IFRS requires that impairment testing be performed at a producing unit level. Under IFRS, if net capitalized costs of the producing unit exceed the estimated net recoverable value of the reserves at a producing unit level, the excess amount is charged to earnings. Under IFRS, write-downs may be reversed in a subsequent period if there is an increase in the net recoverable value of the reserves at the producing unit level. As a result, there is risk of volatile earnings relating to impairment testing under IFRS.

IFRS requires that expenditures that meet the definition of exploration activities be classified and assessed separately for impairment. If such exploration activities are deemed to be "unsuccessful", the related expenditures must be written-off against earnings. As a result, there may be frequent write-downs and in turn volatile earnings relating to exploration expenditures under IFRS.

IFRS requires that gains and losses on sale of properties be recorded through earnings when realized. As a result, there may be volatile earnings relating to gains and losses on sale of assets under IFRS.

Under IFRS, the accounting for derivatives may result in non-cash charges against net income as a result of changes in the fair market value of derivative instruments. A decrease in the fair market value of the derivative instruments as the result of fluctuations in commodity prices and foreign exchange rates may result in a write-down of net assets and a non-cash charge against net income. Such write-downs and non-cash charges may be temporary in nature if the fair market value subsequently increases.

For more information as to the effect of initial adoption of IFRS, see the section in our Management's Discussion and Analysis for the year ended December 31, 2011 under the heading "Financial Reporting Update – Transition to IFRS" which section is incorporated in this Annual Information Form by reference and is found on SEDAR at *www.sedar.com.*

Securing and maintaining title to our properties is subject to certain risks

Our properties are held in the form of licenses and leases and working interests in licenses and leases. If we or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of a license or lease or the working interest relating to a license or lease may have a material adverse effect on our results of operations and business. In addition title to the properties can become subject to dispute and defeat our claim to title over certain of our properties. Furthermore, there may be legislative changes which affect title, to the oil and natural gas properties the Corporation controls that, if successful or made into law, could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. We are not aware that any material claims have been made in respect of our properties and assets; however, if a claim arose and was successful this could have an adverse effect on us and our operations.

Risk Factors Applicable to Residents of the United States and Other Non-Residents of Canada

There is limited ability of residents in the United States to enforce civil remedies

ARC Resources is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. Most of our directors and all of our officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all of our assets and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against ARC Resources or against any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

There are differences in reporting practices in Canada and the United States

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the Securities Exchange Commission by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not generally included or prohibited under rules of the Securities Exchange Commission and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties); however, we also follow the United States practice of separately reporting reserve volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves; whereas the Securities Exchange Commission requires that prices and costs be averaged for the 12 months prior to the date of the reserve report.

We included in this Annual Information Form estimates of proved and proved plus probable reserves. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. The Securities Exchange Commission generally prohibits the inclusion of estimates of probable reserves in filings made with it. This prohibition does not apply to us because we are a Canadian foreign private issuer.

We have included in the Annual Information Form estimates of Economic Contingent Resources. Economic Contingent Resources are a class of resources and should not be confused with reserves and are subject to the definitions, disclaimers and warnings set forth under the heading "*Statement of Reserves Data and Other Oil and Gas information – Contingent Resource Estimates*". The Securities Exchange Commission prohibits the inclusion of Contingent Resource estimates in filings made with it. This prohibition does not apply to us because we are a Canadian foreign private issuer.

As a consequence of the foregoing, our reserve estimates and production volumes in this Annual Information Form may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

There is additional taxation applicable to dividends paid to non-residents

Dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25% unless the rate is reduced under the provisions of an applicable double taxation treaty. Where a non-resident is a United States resident entitled to benefits of the *Canada – United States Income Tax Convention, 1980* and is the beneficial owner of the dividends then the rate of Canadian withholding tax is generally reduced to 15%.

There is a foreign exchange risk to non-resident Shareholders

Our dividends are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to their home currency.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary and Toronto.

MATERIAL CONTRACTS

The following comprises particulars of every material contract of ARC that was entered into within the most recently completed financial year, or entered into before the most recently completed financial year which is still in effect, other than a contract entered into in the ordinary course of business:

1. Amended and Restated Credit Agreement dated as of August 4, 2010 between ARC Resources and a syndicate of lenders, and an administrative agent, as amended January 1, 2011 and September 26, 2011 providing for an extendible revolving credit facility up to Cdn $1 billion.

2. Amended and Restated Uncommitted Master Shelf Agreement as of December 15, 2005 between ARC Resources and various purchasers, as amended on May 17, 2006, April 14, 2009, February 22, 2010 and January 1, 2011, providing for the issuance and sale of up to an aggregate principal amount of US $225 million in notes of which US $56.3 million 5.42% Series C Notes due December 15, 2017 and US $50 million 4.98% Series D Notes due March 5, 2019 are currently outstanding.

3. Note Purchase Agreement dated as of April 27, 2004 between ARC Resources and various purchasers, as amended on April 14, 2009, March 31, 2010 and January 1, 2011, with respect to US $62.5 million 4.62% Series A Notes due April 27, 2014 and US $62.5 million 5.10% Series B Notes due April 27, 2016 of which US $19.2 million and US $24.0 million, respectively, are currently outstanding.

4. Note Purchase Agreement dated as of April 14, 2009 between ARC Resources and various purchasers, as amended January 1, 2011 with respect to US $67.5 million 7.19% Series C Notes due April 14, 2016, US $35 million 8.21% Series D Notes due April 14, 2021 and Cdn $29 million 6.50% Series E Notes due April 14, 2016.

5. Note Purchase Agreement dated as of May 27, 2010 between ARC Resources and various purchasers, as amended January 1, 2011 with respect to US $150 million 5.36% Series F Notes due May 27, 2022.

For more information in relation to these material contracts, see "*Other Information Relating to Our Business – Borrowings*". Copies of each of these documents have been filed on SEDAR at *www.sedar.com*.

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator, and Deloitte & Touche LLP, our auditors. As at the date hereof the designated professionals of GLJ, as a group, beneficially owned, directly or indirectly, less than 1 per cent of our outstanding securities, including the securities of our associates and affiliates. Deloitte & Touche LLP is the auditor of ARC Resources and is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of ARC Resources or of any of our associate or affiliate entities. Allan R. Twa, the Corporate Secretary of ARC Resources, is a partner of Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information including remuneration and indebtedness of directors and officers of ARC Resources, principal holders of the Common Shares and options to purchase Common Shares, is contained in the Information Circular - Proxy Statement of the Corporation which relates to the Annual Meeting of Shareholders to be held on May 15, 2012. Additional financial information is provided in our consolidated financial statements and accompanying management's discussion and analysis for the year ended December 31, 2011, which have been filed on our SEDAR profile at *www.sedar.com*. Other additional information relating to us may be found on our SEDAR profile at *www.sedar.com*.

APPENDIX A
FORM 51-101F2

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of ARC Resources Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2011, 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 per cent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2011, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate, $millions)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	Corporate Evaluation January 17, 2012	Canada	-	6,520	-	6,520

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

Dated February 15, 2012

(signed) "James H. Willmon"
James H. Willmon, P.Eng
Vice President

APPENDIX B
FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of ARC Resources Ltd. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's and its subsidiaries' oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2011 estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's and its subsidiaries' reserves data. The report of the independent qualified reserves evaluator is presented below.

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

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

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed 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

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

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

(f) the content and filing of this report.

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

(signed) "*John P. Dielwart*"
John P. Dielwart
Chief Executive Officer

(signed) "*Myron Stadnyk*"
Myron Stadnyk
President and Chief Operating Officer

(signed) "*James Houck*"
James Houck
Director and Chairman of the Reserves Committee

(signed) "*Fred J. Dyment*"
Fred J. Dyment
Director and Member of the Reserves Committee

March 21, 2012

APPENDIX C

MANDATE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the Board of Directors of ARC Resources Ltd. (the "**Corporation**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board of Director approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee, with respect to the Corporation and its subsidiaries, are as follows:

- To assist Directors to meet their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation and related matters.
- To provide better communication between directors and external auditors.
- To ensure the external auditors' independence.
- To increase the credibility and objectivity of financial reports.
- To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Mandate and Responsibilities of Committee

- It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to the Corporation's internal control systems, including in particular relating to derivative instruments:
  - identifying, monitoring and mitigating business risks.
  - ensuring compliance with legal and regulatory requirements.
- It is a primary responsibility of the Committee to review the annual and quarterly financial statements of the Corporation prior to their submission to the Board of Directors for approval. The process should include but not be limited to:
  - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
  - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
  - reviewing accounting treatment of unusual or non-recurring transactions;
  - ascertaining compliance with covenants under loan agreements;
  - reviewing financial reporting relating to asset retirement obligations;
  - reviewing disclosure requirements for commitments and contingencies;
  - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
  - reviewing unresolved differences between management and the external auditors;
  - obtain explanations of significant variances with comparative reporting periods; and
  - determine through inquiry if there are any related party transactions and ensure the nature and extent of such transactions are properly disclosed.

- The Committee is to review the financial statements and related information included in prospectuses, management discussion and analysis (MD&A), information circular-proxy statements and annual information forms (AIF), prior to Board approval.

- With respect to the appointment of external auditors by the Board, the Committee shall:

  - be directly responsible for overseeing the work of the external auditors engaged for the purpose of issuing an auditors' report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditor regarding financial reporting;
  - review management's recommendation for the appointment of external auditors and recommend to the Board appointment of external auditors and the compensation of the external auditors;
  - review the terms of engagement of the external auditors, including the appropriateness and reasonableness of the auditors' fees;
  - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
  - review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors.

- Review with external auditors (and internal auditor if one is appointed by the Corporation) their assessment of the internal controls of the Corporation, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses.

- The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

- Review all public disclosure containing audited or unaudited financial information before release.

- Review financial reporting relating to risk exposure.

- Satisfy itself that adequate procedures are in place for the review of the Corporation's public disclosure of financial information from the Corporation's financial statements and periodically assess the adequacy of those procedures.

- Establish procedures for:

  - the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and
  - the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

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

- Review any other matters that the Audit Committee feels are important to its mandate or that the Board chooses to delegate to it.

- Undertake annually a review of this mandate and make recommendations to the Policy and Board Governance Committee as to proposed changes.

Composition

- This Committee shall be composed of at least three individuals appointed by the Board from amongst its members, all of which members will be independent (within the meaning of National Instrument 52-110 Audit

Committees) unless the Board determines to rely on an exemption in NI 52-110. "Independent" generally means free from any business or other direct or indirect material relationship with the Corporation that could, in the view of the Board, reasonably interfere with the exercise of the member's independent judgment.

- The Secretary to the Board shall act as Secretary of the Committee.

- A quorum shall be a majority of the members of the Committee.

- All of the members must be financially literate within the meaning of NI 52-110 unless the Board has determined to rely on an exemption in NI 52-110. Being "financially literate" means members have 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 issues that can reasonably be expected to be raised by the Corporation's financial statements.

Meetings

- The Committee shall meet at least four times per year and/or as deemed appropriate by the Committee Chair.

- The Committee shall meet not less than quarterly with the auditors, independent of the presence of management.

- Agendas, with input from management, shall be circulated to Committee members and relevant management personnel along with background information on a timely basis prior to the Committee meetings.

- Minutes of each meeting shall be prepared by the Secretary to the Committee.

- The Chief Executive Officer and the Chief Financial Officer or their designates shall be available to attend at all meetings of the Committee upon the invitation of the Committee.

- The Controller, Treasurer and such other staff as appropriate to provide information to the Committee shall attend meetings upon invitation by the Committee.

Reporting / Authority

- Following each meeting, in addition to a verbal report, the Committee will report to the Board by way of providing copies of the minutes of such Committee meeting at the next Board meeting after a meeting is held (these may still be in draft form).

- Supporting schedules and information reviewed by the Committee shall be available for examination by any director.

- The Committee shall have the authority to investigate any financial activity of the Corporation and to communicate directly with the internal and external auditors. All employees are to cooperate as requested by the Committee.

- The Committee may retain, and set and pay the compensation for, persons having special expertise and/or obtain independent professional advice to assist in fulfilling its duties and responsibilities at the expense of the Corporation.