



2014

Annual  
Information Form  
March 17, 2015

## TABLE OF CONTENTS

|   |           |
|---|-----------|
| <b>GLOSSARY OF TERMS.....</b>   | <b>3</b>  |
| <b>SPECIAL NOTES TO READER.....</b>                                       | <b>4</b>  |
| Regarding Forward-Looking Statements and Risk Factors .....               | 4         |
| Access to Documents .....   | 5         |
| Abbreviations and Conversions .....                                       | 5         |
| <b>ARC RESOURCES LTD.....</b>   | <b>6</b>  |
| General .....   | 6         |
| Organizational Structure.....   | 6         |
| Strategy.....   | 7         |
| Development of our Business.....  | 8         |
| Recent Developments.....  | 9         |
| <b>STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION .....</b> | <b>10</b> |
| Disclosure of Reserves Data .....   | 10        |
| Reserves Data – Based on Forecast Prices and Costs.....                   | 10        |
| Forecast Prices and Costs .....   | 12        |
| Definitions and Notes to Reserves Data Tables .....                       | 13        |
| Reconciliations of Changes in Reserves .....                              | 16        |
| Future Development Costs.....   | 17        |
| Undeveloped Reserves .....  | 17        |
| Other Oil and Gas Information.....  | 19        |
| Economic Contingent Resource Estimates .....                              | 22        |
| Oil And Gas Wells.....  | 23        |
| Properties with no Attributable Reserves .....                            | 24        |
| Forward Contracts .....   | 24        |
| Abandonment and Reclamation Costs.....                                    | 25        |
| Tax Horizon.....  | 26        |
| Capital Expenditures.....   | 26        |
| Exploration and Development Activities .....                              | 26        |
| Production Estimates .....  | 27        |
| Production History .....  | 28        |
| Marketing Arrangements.....   | 30        |
| <b>SHARE CAPITAL OF ARC RESOURCES.....</b>                                | <b>31</b> |
| Common Shares.....  | 31        |
| Preferred Shares .....  | 31        |
| <b>OTHER INFORMATION RELATING TO OUR BUSINESS .....</b>                   | <b>32</b> |
| Borrowing.....  | 32        |
| Stock Dividend Program and Dividend Reinvestment Plan .....               | 33        |
| <b>DIRECTORS AND EXECUTIVE OFFICERS .....</b>                             | <b>33</b> |
| Membership of Board Committees.....                                       | 35        |
| Officer Biographies .....   | 36        |
| <b>AUDIT COMMITTEE DISCLOSURES.....</b>                                   | <b>38</b> |
| Members of the Audit Committee .....                                      | 38        |
| Principal Accountant Fees and Services .....                              | 39        |
| <b>CONFLICTS OF INTEREST .....</b>  | <b>39</b> |
| <b>INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS.....</b>    | <b>40</b> |

|  |           |
|--|-----------|
| <b>DIVIDENDS and distributions .....</b>   | <b>40</b> |
| Dividend Policy .....  | 40        |
| Dividend History .....   | 40        |
| <b>MARKET FOR SECURITIES .....</b>   | <b>41</b> |
| <b>INDUSTRY CONDITIONS.....</b>  | <b>41</b> |
| Pricing and Marketing .....  | 41        |
| The North American Free Trade Agreement .....  | 42        |
| Royalties and Incentives .....   | 42        |
| Land Tenure.....   | 45        |
| Environmental Regulation .....   | 45        |
| Liability Management Rating Programs.....  | 47        |
| Climate Change Regulation.....   | 48        |
| <b>RISK FACTORS.....</b>   | <b>50</b> |
| Risks Relating to Our Business and Operations.....   | 50        |
| Risk Factors Applicable to Residents of the United States and Other Non-Residents of Canada..... | 57        |
| <b>TRANSFER AGENT AND REGISTRAR .....</b>  | <b>58</b> |
| <b>MATERIAL CONTRACTS .....</b>  | <b>58</b> |
| <b>INTEREST OF EXPERTS.....</b>  | <b>59</b> |
| <b>ADDITIONAL INFORMATION .....</b>  | <b>59</b> |
| APPENDIX A - REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATION OR AUDITOR     |           |
| APPENDIX B - REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION           |           |
| APPENDIX C - MANDATE OF THE AUDIT COMMITTEE  |           |

## GLOSSARY OF TERMS

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

**ARC, we, us, our, Corporation** 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., a corporation formed by amalgamation under the *Business Corporations Act* (Alberta);

**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;

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

**GLJ Report** means the report prepared by GLJ on January 12, 2015 and dated February 11, 2015 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to ARC's properties at December 31, 2014 and evaluating the crude oil, natural gas and natural gas liquids resources located in the NE BC Montney;

**NE BC Montney** means our lands in northeastern British Columbia comprised of the Dawson, Parkland, Tower, Red Creek, 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*;

**NI 51-102** means National Instrument 51-102 *Continuous Disclosure Obligations*;

**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 corporation, 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 our reserves and 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 expenditure 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; stock market volatility; uncertainties relating to market valuations; 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 oil and natural gas and other aspects of our operations; our reliance on hydraulic fracturing; 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; risks described in further detail under "Risk Factors" herein; 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 our SEDAR profile at [www.sedar.com](http://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 – 4<sup>th</sup> Avenue SW, Calgary, Alberta, T2P 0H7.

## Abbreviations and Conversions

| Oil and Natural Gas Liquids |   |
|-----------------------------|---|
| bbbl                        | barrel  |
| Mbbl                        | thousand barrels  |
| MMbbl                       | million barrels   |
| bbbl/d                      | barrels per day   |
| NGL                         | natural gas liquids   |
| Natural Gas                 |   |
| Mcf                         | thousand cubic feet   |
| Mcf/d                       | thousand cubic feet per day   |
| MMcf                        | million cubic feet  |
| MMcf/d                      | million cubic feet per day  |
| Bcf                         | billion cubic feet  |
| Bcfe                        | billion cubic feet equivalent   |
| Tcf                         | trillion cubic feet   |
| MMbtu                       | million British thermal units   |
| Other                       |   |
| API                         | Indication of specific gravity of crude oil measured on the API gravity scale |
| boe                         | barrels of oil equivalent   |
| boe/d                       | barrels of oil equivalent per day   |
| GJ                          | gigajoules  |
| Mboe                        | thousand barrels of oil equivalent  |
| \$MM                        | million dollars   |

We have adopted the standard of 6 Mcf:1 boe when converting natural gas to boe. Boe 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.**

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

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       |

## ARC RESOURCES LTD.

### General

ARC Resources was formed by amalgamation under the *Business Corporations Act* (Alberta). Prior to January 1, 2011, ARC was one of Canada's largest conventional oil and gas royalty trusts and was founded in 1996.

Currently, ARC is one of Canada's leading conventional oil and gas corporations with average production in 2014 of 112,387 boe per day. ARC's business activities include the exploration, development and production of crude oil, natural gas and natural gas liquids in five core areas across western Canada. ARC has focused on the acquisition and development of resource rich properties that provide an option for both near-term and long-term growth. ARC trades on the Toronto Stock Exchange under the symbol ARX and currently pays a monthly dividend to its Shareholders.

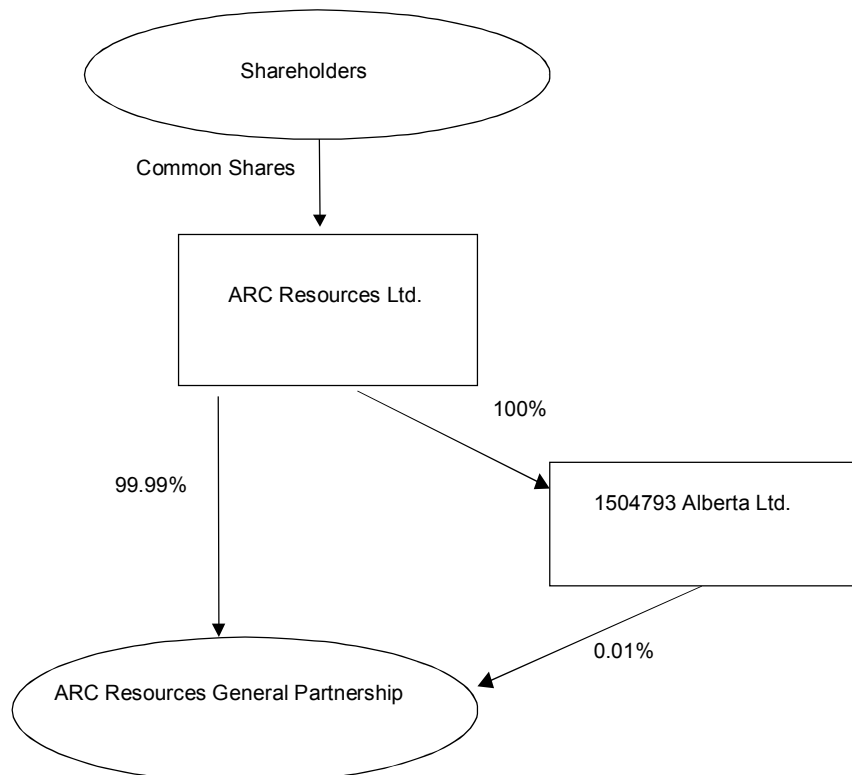
As of the end of 2014, ARC had approximately 603 employees with 346 professional, technical and support staff in the Calgary office and 257 individuals located across ARC's operating areas in western Canada.

Our principal office is located at 1200, 308 – 4<sup>th</sup> Avenue SW, Calgary, Alberta, T2P 0H7 and our registered office is located at 2400, 525 – 8<sup>th</sup> Avenue SW, Calgary, Alberta, T2P 1G1.

### 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:



## Strategy

ARC's vision is to be a leading energy producer, focused on delivering results through its strategy of **risk-managed value creation**. ARC is committed to providing superior long-term financial returns for its shareholders, creating a culture where respect for the individual is paramount and action and passion are rewarded. ARC runs its business in a manner that protects the safety of employees, communities and the environment. ARC's vision is realized through the four pillars of its strategy:

1. **High quality, long-life assets** – ARC's unique suite of assets include both growth and base assets. ARC's growth assets consist of world-class resource play properties, primarily concentrated in the Montney geological formation in northeast British Columbia and northern Alberta, and the Cardium formation in the Pembina area of Alberta. These assets provide substantial growth opportunities, which ARC will pursue to create value through long-term profitable development. ARC's base assets consist of core properties located throughout Alberta, Saskatchewan and Manitoba. The base assets deliver stable production and contribute significant cash flow to fund future development and support ARC's dividend.
2. **Operational excellence** – ARC is focused on capital discipline and cost management to extract the maximum return on its investments while operating in a safe and environmentally responsible manner. Production from individual oil and natural gas wells naturally declines over time. In any one year, ARC approves a budget to drill new wells with the intent to first replace production declines and second to potentially increase production volumes, when both can be done profitably. At times, ARC may also acquire strategic producing or undeveloped properties to enhance current production and reserves or to provide potential future drilling locations. Alternatively, it may strategically dispose of non-core assets that no longer meet its investment criteria.
3. **Financial flexibility** – ARC provides returns to shareholders through a combination of a monthly dividend, currently \$0.10 per share per month, and a potential for capital appreciation. ARC's goal is to fund capital expenditures necessary to replace production declines and dividend payments using funds from operations<sup>(1)</sup>. ARC will finance value creating activities through a combination of sources including funds from operations, proceeds from ARC's Dividend Reinvestment Program ("**DRIP**"), reduced funding required under the Stock Dividend Program ("**SDP**"), proceeds from property dispositions, debt capacity, and if necessary, equity issuance. ARC chooses to maintain prudent debt levels, targeting its net debt to be one to 1.5 times annualized funds from operations and less than 20 per cent of total capitalization over the long-term <sup>(1)</sup>.
4. **Top talent and strong leadership culture** – ARC is committed to the attraction, retention and development of the best and brightest people in the industry. ARC's employees conduct business every day in a culture of trust, respect, integrity and accountability. Building leadership talent at all levels of the organization is a key focus. ARC is also committed to corporate leadership through community investment, environmental reporting practices and open communication with all stakeholders. As of the end of December 2014, ARC had approximately 603 employees with 346 professional, technical and support staff in the Calgary office, and 257 individuals located across ARC's operating areas in western Canada.

Note:

- (1) Funds from operations, net debt, and total capitalization are additional generally accepted accounting principles ("**GAAP**") measures which may not be comparable to similar additional GAAP measures used by other entities. For more information, see the section entitled "*Additional GAAP Measures*" contained within our Management's Discussion and Analysis for the year ended December 31, 2014, which note is incorporated in this Annual Information Form by reference and is found on our SEDAR profile at [www.sedar.com](http://www.sedar.com). Also refer to the section "*Funds from Operations*" section within the Management's Discussion and Analysis for a reconciliation of ARC's net income to funds from operations and cash flow from operating activities, which note is also incorporated into this Annual Information Form and can also be found on our SEDAR profile at [www.sedar.com](http://www.sedar.com).

## Development of our Business

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

### 2012

Production was 93,546 boe per day while funds from operations were \$719.8 million.

Dividends paid to investors were maintained at \$0.10 per share per month throughout the year resulting in a total of \$357.4 million being distributed of which \$117.4 million was reinvested into Common Shares through the DRIP.

Despite the reduction in the 2012 capital budget from \$760 million to actual 2012 capital spending of \$608 million, ARC achieved its production guidance and increased crude oil and liquids production 15 per cent relative to 2011. Capital expenditures were \$429.8 million (71 per cent) on drilling and completions, \$131.6 million (22 per cent) on plant and facilities, \$31.8 million on geological and geophysical expenditures, \$9.5 million on undeveloped Crown land, and the remaining on other corporate capital spending. In addition, ARC spent \$36.5 million on “tuck-in” acquisitions in key areas (\$32.4 million net of non-core property dispositions).

In February 2012, ARC commissioned a new 30 MMcf per day Ante Creek gas plant which resulted in production from the Ante Creek field increasing from 8,000 boe per day prior to the commissioning of the plant to 10,500 boe per day by the end of the second quarter. Late in 2012, ARC received all regulatory approvals to construct 120 MMcf per day of gas processing and liquids handling facilities in the Parkland/Tower area. The plant has a designed capacity to handle up to 130 bbls of oil and liquids per MMcf. The construction of the first 60 MMcf per day phase of the facility commenced in late 2012.

On August 22, 2012, ARC issued 14.6 million Common Shares at \$23.65 per share for net proceeds of \$330.9 million. The proceeds were used to pay down existing debt, freeing up capacity that could be put towards the 2013 capital program, and at December 31, 2012, contributed to ARC's working capital surplus of \$41.8 million.

On August 23, 2012, ARC issued US\$360 million and Cdn\$40 million of long-term fixed rate notes through a private placement to secure additional credit capacity by paying down indebtedness under ARC's credit facility and to capitalize on low long-term interest rates. The notes have an average term of 9.6 years and bear interest at an average rate of 3.8 per cent.

ARC extended its syndicated revolving credit facility for one additional year until August 3, 2016 at existing terms. At December 31, 2012, ARC had total unutilized credit capacity of \$1.2 billion. At the end of 2012, net debt to annualized funds from operations ratio was 1.0 times and net debt was approximately nine per cent of ARC's total capitalization; both metrics well within target levels.

### 2013

Production was a record 96,087 boe per day punctuated by the achievement of reaching the 100,000 boe per day milestone in the fourth quarter. Funds from operations were \$861.8 million. ARC's full year 2013 production met guidance targets despite the divestment of approximately 2,000 boe per day of gas weighted non-core production during 2013.

Dividends paid to investors were maintained at \$0.10 per share per month throughout the year resulting in a total of \$374.0 million being distributed of which \$130.7 million was reinvested into Common Shares through the DRIP and SDP.

Capital expenditures including Crown land purchases and excluding property acquisitions and dispositions were \$874.2 million, of which \$568.4 million (65 per cent) was drilling and completions expenditures, \$267.7 million (31 per cent) was plant and facility expenditures, \$19.2 million was geological and geophysical expenditures, \$14.3 million was Crown land purchases, and the remaining was other corporate capital spending. During 2013, ARC divested of certain non-core assets for gross proceeds of \$89.8 million with approximately 2,000 boe per day of associated production. In addition, ARC completed \$36.4 million of “tuck-in” acquisitions during the full year targeting the Northeast BC and Pembina core areas.

During the fourth quarter, ARC completed construction of the Parkland/Tower gas processing and liquids handling facility, providing design capacity of approximately 60 MMcf per day of natural gas, 5,000 bbls per day per day of oil, and 3,000 bbls per day of NGLs. ARC initiated the flow of restricted volumes of oil and natural gas through the facility late in the fourth quarter. Upon commissioning of the new facility, ARC had an inventory of 26 previously drilled wells

at Parkland and Tower which were tied into the facility and ready to be brought on-stream. The existing wells were systematically brought on production over the course of the first quarter of 2014.

Also during the fourth quarter, ARC advanced its Sunrise pilot project to commercial development and proceeded with the construction of an ARC operated 60 MMcf per day gas processing facility which is scheduled to be on-stream by late 2015.

ARC extended its syndicated revolving credit facility for one additional year until October 10, 2017 at more favorable pricing terms. At December 31, 2014, ARC had total unutilized credit capacity of \$1.1 billion. At the end of 2013, net debt to annualized funds from operations ratio was 1.2 times and net debt was approximately 10 per cent of ARC's total capitalization; both metrics well within target levels.

Effective December 13, 2013 Terry Anderson was appointed to the position of Senior Vice President and Chief Operating Officer and on this same date Cam Kramer resigned from this position for personal reasons.

## **2014**

ARC achieved record full year production of 112,387 boe per day, which was 17 per cent higher than 2013. New wells at Parkland/Tower and Sunrise, as well as continued strong production at Ante Creek were the primary drivers of higher full year 2014 production. ARC's 2014 annual average production was within the original guidance range of 110,000 to 114,000 boe per day, a significant achievement given the divestment of 2,400 boe per day of production in the second quarter of 2014.

Construction began on the new 60 mmcf per day Sunrise gas processing facility in the fourth quarter of 2014. Construction is on schedule and on budget, with major equipment arriving on site throughout the fourth quarter. ARC plans to commission the new facility in the fourth quarter of 2015 and expects to fill the facility by early 2016.

Capital expenditures for 2014 totaled \$945.5 million. ARC's capital program focused primarily on oil and liquids-rich opportunities at Parkland/Tower, Ante Creek, Pembina, and southeast Saskatchewan along with spending on natural gas development at Dawson and Sunrise. ARC drilled 187 gross operated wells (139 oil wells, 22 liquids-rich natural gas wells and 26 natural gas wells) in 2014.

ARC completed \$134 million of land purchases and "tuck-in" land and infrastructure acquisitions in key development areas during 2014. In the Montney region, ARC grew its land position by approximately 120 net sections in 2014. ARC is currently the third largest Montney land holder with approximately 990 net Montney sections, including 529 net sections in Northeast British Columbia and an additional 461 net Montney sections in northern Alberta.

ARC has a \$1.0 billion financial covenant-based syndicated credit facility with 12 banks. This facility was extended in 2014 for one additional year until November 6, 2018. At December 31, 2014, ARC had available credit of \$916.4 million taking into account ARC's year-end working capital deficit on total credit facilities of \$2.2 billion. Net debt to 2014 funds from operations ratio was 1.1 times and net debt was approximately 14 per cent of ARC's total capitalization; both metrics are well within ARC's target levels.

Effective February 5, 2014 Van Dafoe was appointed to the position of Senior Vice President and Chief Financial Officer and on this same date Steve Sinclair transitioned to the position of Senior Vice President of Development. ARC had deliberately planned this CFO succession process over the previous few years.

## **Recent Developments**

During the month of January 2015, ARC issued 17.9 million shares for net proceeds of approximately \$386 million for the purpose of temporarily repaying bank indebtedness, increasing working capital and funding ongoing capital programs.

## STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

### Disclosure of Reserves Data

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, 2014 and the preparation date of the Statement is January 12, 2015. The reserves data conforms to the requirements of NI 51-101.

The reserves data set forth below is based upon an evaluation by GLJ and contained in the GLJ Report dated February 11, 2015. 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. Future net revenues have been presented on a before and after tax basis. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves.

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".**

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.

### Reserves Data – Based on Forecast Prices and Costs

Company Gross reserves information presented herein is consistent with reserves information disclosed in the February 11, 2015 News Release titled "ARC Resources Ltd. Announces 210 Per Cent Produced Reserves Replacement in 2014".

#### *Summary of Oil and Gas Reserves – Based on Forecast Prices and Costs*

| Company Gross Reserves            | Light & Medium Crude Oil (Mbbbl) | Heavy Crude Oil (Mbbbl) | Total Crude Oil (Mbbbl) | NGLs (Mbbbl)  | Natural Gas (Bcf) | Total 2014 (Mboe) |
|-----------------------------------|----------------------------------|-------------------------|-------------------------|---------------|-------------------|-------------------|
| <b>PROVED</b>                     |                                  |                         |                         |               |                   |                   |
| Developed Producing               | 86,543                           | 1,447                   | 87,990                  | 12,136        | 656.3             | 209,509           |
| Developed Non-Producing           | 1,645                            | -                       | 1,645                   | 700           | 106.9             | 20,164            |
| Undeveloped                       | 15,191                           | 105                     | 15,296                  | 8,833         | 769.6             | 152,390           |
| <b>TOTAL PROVED</b>               | <b>103,379</b>                   | <b>1,552</b>            | <b>104,931</b>          | <b>21,668</b> | <b>1,532.8</b>    | <b>382,063</b>    |
| Probable                          | 46,624                           | 481                     | 47,105                  | 18,786        | 1,348.8           | 290,684           |
| <b>TOTAL PROVED PLUS PROBABLE</b> | <b>150,003</b>                   | <b>2,032</b>            | <b>152,035</b>          | <b>40,454</b> | <b>2,881.6</b>    | <b>672,748</b>    |

**Summary of Oil and Gas Reserves – Based on Forecast Prices and Costs**

| <b>Company Net Reserves</b>       | <b>Light &amp; Medium Crude Oil (Mbbl)</b> | <b>Heavy Crude Oil (Mbbl)</b> | <b>Total Crude Oil (Mbbl)</b> | <b>NGLs (Mbbl)</b> | <b>Natural Gas (Bcf)</b> | <b>Total 2014 (Mboe)</b> |
|-----------------------------------|--|-------------------------------|-------------------------------|--------------------|--------------------------|--------------------------|
| <b>PROVED</b>                     |  |                               |                               |                    |                          |                          |
| Developed Producing               | 76,170                                     | 1,518                         | 77,688                        | 9,303              | 551.0                    | 178,826                  |
| Developed Non-Producing           | 1,393                                      | -                             | 1,393                         | 569                | 90.3                     | 17,007                   |
| Undeveloped                       | 13,458                                     | 87                            | 13,545                        | 7,349              | 637.1                    | 127,070                  |
| <b>TOTAL PROVED</b>               | <b>91,020</b>                              | <b>1,605</b>                  | <b>92,625</b>                 | <b>17,222</b>      | <b>1,278.3</b>           | <b>322,904</b>           |
| Probable                          | 40,049                                     | 491                           | 40,540                        | 14,981             | 1,081.4                  | 235,756                  |
| <b>TOTAL PROVED PLUS PROBABLE</b> | <b>131,069</b>                             | <b>2,096</b>                  | <b>133,165</b>                | <b>32,203</b>      | <b>2,359.7</b>           | <b>558,659</b>           |

**Net Present Value of Future Net Revenues – Based on Forecast Prices and Costs**

| <b>Before Tax</b>                 | <b>Undiscounted (\$MM)</b> | <b>Discounted at 5% (\$MM)</b> | <b>Discounted at 10% (\$MM)</b> | <b>Discounted at 15% (\$MM)</b> | <b>Discounted at 20% (\$MM)</b> |
|-----------------------------------|----------------------------|--------------------------------|---------------------------------|---------------------------------|---------------------------------|
| <b>PROVED</b>                     |                            |                                |                                 |                                 |                                 |
| Developed Producing               | 5,838                      | 4,047                          | 3,105                           | 2,530                           | 2,143                           |
| Developed Non-Producing           | 392                        | 266                            | 200                             | 159                             | 132                             |
| Undeveloped                       | 2,073                      | 1,036                          | 510                             | 213                             | 32                              |
| <b>TOTAL PROVED</b>               | <b>8,303</b>               | <b>5,350</b>                   | <b>3,815</b>                    | <b>2,902</b>                    | <b>2,308</b>                    |
| Probable                          | 7,521                      | 3,623                          | 2,093                           | 1,352                           | 940                             |
| <b>TOTAL PROVED PLUS PROBABLE</b> | <b>15,823</b>              | <b>8,973</b>                   | <b>5,907</b>                    | <b>4,254</b>                    | <b>3,248</b>                    |
| <b>After Tax<sup>(1)(2)</sup></b> |                            |                                |                                 |                                 |                                 |
| <b>PROVED</b>                     |                            |                                |                                 |                                 |                                 |
| Developed Producing               | 4,995                      | 3,536                          | 2,757                           | 2,274                           | 1,946                           |
| Developed Non-Producing           | 292                        | 198                            | 147                             | 117                             | 97                              |
| Undeveloped                       | 1,545                      | 726                            | 307                             | 70                              | (74)                            |
| <b>TOTAL PROVED</b>               | <b>6,832</b>               | <b>4,460</b>                   | <b>3,211</b>                    | <b>2,461</b>                    | <b>1,969</b>                    |
| Probable                          | 5,604                      | 2,667                          | 1,512                           | 954                             | 645                             |
| <b>TOTAL PROVED PLUS PROBABLE</b> | <b>12,436</b>              | <b>7,127</b>                   | <b>4,723</b>                    | <b>3,415</b>                    | <b>2,614</b>                    |

Notes:

(1) Based on ARC's estimated tax pools at year-end 2014.

- (2) 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 audited consolidated financial statements for the year ended December 31, 2014 and the related Management's Discussion and Analysis should be consulted for information at the business entity level.

**Total Future Net Revenue (Undiscounted) – Based on 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               | 20,252         | 2,880            | 6,732                  | 2,078                    | 259                                      | 8,303   | 1,471               | 6,832  |
| Proved Plus Probable Reserves | 36,209         | 5,526            | 10,907                 | 3,637                    | 315                                      | 15,823  | 3,387               | 12,436                                       |

**Future Net Revenue By Production Group – Based on Forecast Prices and Costs**

| Reserves Category             | Production Group                          | Future Net Revenue Before Income Taxes (Discounted at 10% per year) (\$MM) | Per Unit <sup>(4)</sup> |
|-------------------------------|---|--|-------------------------|
| Proved Reserves               | Light and Medium Crude Oil <sup>(1)</sup> | 2,263  | \$19.68/boe             |
|                               | Heavy Oil <sup>(1)(2)</sup>               | 27   | \$18.23/boe             |
|                               | Natural Gas <sup>(3)</sup>                | 1,524  | \$1.23/Mcfe             |
| <b>Total</b>                  |   | <b>3,815</b>   | <b>\$11.81/boe</b>      |
| Proved Plus Probable Reserves | Light and Medium Crude Oil <sup>(1)</sup> | 3,146  | \$18.31/boe             |
|                               | Heavy Oil <sup>(1)(2)</sup>               | 35   | \$18.03/boe             |
|                               | Natural Gas <sup>(3)</sup>                | 2,726  | \$1.18/Mcfe             |
| <b>Total</b>                  |   | <b>5,907</b>   | <b>\$10.57/boe</b>      |

Notes:

- (1) Including solution gas and other by-products.  
(2) Per unit revenue positively impacted by approximately 30 per cent of value coming from royalty interest reserves.  
(3) Including by-products but excluding solution gas.  
(4) Unit values are based on Net Reserves.

**Forecast Prices and Costs**

These are prices and costs that are generally acceptable, in the opinion of GLJ, 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, 2014, and inflation and exchange rates utilized in the GLJ Report were as follows:

### Summary of Forecast Prices and Inflation Rate Assumptions

|            | Oil                             |  |                                    |                                    | Natural Gas                  | Edmonton Liquids Prices |                    |                           |                                      |   |
|------------|---------------------------------|--|------------------------------------|------------------------------------|------------------------------|-------------------------|--------------------|---------------------------|--------------------------------------|---|
|            | 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) | AECO Gas Price (\$Cdn/MMbtu) | Propane (\$Cdn/bbl)     | Butane (\$Cdn/bbl) | Pentanes Plus (\$Cdn/bbl) | Inflation Rate <sup>(1)</sup> %/Year | Exchange Rate <sup>(2)</sup> (\$US/\$Cdn) |
| Forecast   |                                 |  |                                    |                                    |                              |                         |                    |                           |                                      |   |
| 2015       | 62.50                           | 64.71                                  | 48.89                              | 61.47                              | 3.31                         | 19.63                   | 52.91              | 69.24                     | 2.0                                  | 0.850                                     |
| 2016       | 75.00                           | 80.00                                  | 60.68                              | 76.00                              | 3.77                         | 32.00                   | 60.80              | 85.60                     | 2.0                                  | 0.875                                     |
| 2017       | 80.00                           | 85.71                                  | 65.09                              | 81.43                              | 4.02                         | 38.57                   | 65.14              | 91.71                     | 2.0                                  | 0.875                                     |
| 2018       | 85.00                           | 91.43                                  | 69.49                              | 86.86                              | 4.27                         | 41.14                   | 69.49              | 97.83                     | 2.0                                  | 0.875                                     |
| 2019       | 90.00                           | 97.14                                  | 73.90                              | 92.29                              | 4.53                         | 43.71                   | 73.83              | 103.94                    | 2.0                                  | 0.875                                     |
| 2020       | 95.00                           | 102.86                                 | 78.30                              | 97.71                              | 4.78                         | 46.29                   | 78.17              | 110.06                    | 2.0                                  | 0.875                                     |
| 2021       | 98.54                           | 106.18                                 | 80.87                              | 100.87                             | 5.03                         | 47.78                   | 80.70              | 113.62                    | 2.0                                  | 0.875                                     |
| 2022       | 100.51                          | 108.31                                 | 82.51                              | 102.89                             | 5.28                         | 48.74                   | 82.31              | 115.89                    | 2.0                                  | 0.875                                     |
| 2023       | 102.52                          | 110.47                                 | 84.17                              | 104.95                             | 5.53                         | 49.71                   | 83.96              | 118.20                    | 2.0                                  | 0.875                                     |
| 2024       | 104.57                          | 112.67                                 | 85.87                              | 107.04                             | 5.71                         | 50.70                   | 85.63              | 120.56                    | 2.0                                  | 0.875                                     |
| Thereafter | (3)                             | (3)                                    | (3)                                | (3)                                | (3)                          | (3)                     | (3)                | (3)                       | 2.0                                  | 0.875                                     |

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 cent per year from 2024.

ARC's weighted average prices realized for the year ended December 31, 2014, were \$4.76 per Mcf for natural gas, \$91.17 per bbl for light and medium crude oil, \$72.95 per bbl for heavy crude oil and \$63.81 per bbl for natural gas liquids including condensate. Only a minor amount of our production is characterized as heavy oil.

### Definitions and Notes to Reserves Data Tables

In the tables set forth above 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 to 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. Estimated future well abandonment costs related to reserves wells have been taken into account by GLJ in determining the aggregate future net revenue therefrom.
  5. The forecast price and cost assumptions assumed the continuance of current laws and regulations.
  6. All factual data supplied to GLJ was accepted as represented. No field inspection was conducted.
  7. 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 – *Revised 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 per cent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 per cent probability that the quantities actually recovered will equal or exceed the 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.

## Reconciliations of Changes in Reserves

The following table sets forth the reconciliation of our gross reserves as at December 31, 2014, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2014 and as at December 31, 2013 include working interest reserves before royalties payable and without including gross royalties receivable.

### Reconciliation of Gross Reserves By Principal Product Type

|   | Light and<br>Medium<br>Crude<br>(Mbbbl) | Heavy<br>Crude Oil<br>(Mbbbl) | Total<br>Crude Oil<br>(Mbbbl) | NGLs<br>(Mbbbl) | Natural<br>Gas<br>(Bcf) | Total<br>(Mboe) |
|---|---|-------------------------------|-------------------------------|-----------------|-------------------------|-----------------|
| <b>PROVED</b>                                   |   |                               |                               |                 |                         |                 |
| <b>December 31, 2013</b>                        | <b>108,894</b>                          | <b>1,686</b>                  | <b>110,580</b>                | <b>21,383</b>   | <b>1,452.1</b>          | <b>373,976</b>  |
| Discoveries                                     | -                                       | -                             | -                             | -               | -                       | -               |
| Extensions and Improved Recovery <sup>(1)</sup> | 5,772                                   | -                             | 5,772                         | 2,889           | 203.5                   | 42,585          |
| Technical Revisions                             | 2,392                                   | 100                           | 2,492                         | 612             | 80.4                    | 16,499          |
| Acquisitions                                    | 420                                     | -                             | 420                           | 16              | 0.8                     | 572             |
| Dispositions                                    | (49)                                    | (13)                          | (62)                          | (1)             | (40.6)                  | (6,836)         |
| Economic Factors                                | (1,170)                                 | (18)                          | (1,188)                       | (253)           | (15.7)                  | (4,055)         |
| Production                                      | (12,880)                                | (203)                         | (13,083)                      | (2,978)         | (147.7)                 | (40,677)        |
| <b>December 31, 2014</b>                        | <b>103,379</b>                          | <b>1,552</b>                  | <b>104,931</b>                | <b>21,668</b>   | <b>1,532.8</b>          | <b>382,063</b>  |
| <b>PROBABLE</b>                                 |   |                               |                               |                 |                         |                 |
| <b>December 31, 2013</b>                        | <b>44,134</b>                           | <b>468</b>                    | <b>44,602</b>                 | <b>17,500</b>   | <b>1,186.7</b>          | <b>259,888</b>  |
| Discoveries                                     | -                                       | -                             | -                             | -               | -                       | -               |
| Extensions and Improved Recovery <sup>(1)</sup> | 3,432                                   | -                             | 3,432                         | 3,135           | 188.8                   | 38,034          |
| Technical Revisions                             | (1,733)                                 | 8                             | (1,725)                       | (1,819)         | (18.2)                  | (6,576)         |
| Acquisitions                                    | 111                                     | -                             | 111                           | 4               | 0.2                     | 156             |
| Dispositions                                    | (21)                                    | (6)                           | (27)                          | -               | (11.0)                  | (1,865)         |
| Economic Factors                                | 701                                     | 11                            | 712                           | (33)            | 2.2                     | 1,046           |
| Production                                      | -                                       | -                             | -                             | -               | -                       | -               |
| <b>December 31, 2014</b>                        | <b>46,624</b>                           | <b>481</b>                    | <b>47,105</b>                 | <b>18,786</b>   | <b>1,348.8</b>          | <b>290,684</b>  |
| <b>PROVED PLUS PROBABLE</b>                     |   |                               |                               |                 |                         |                 |
| <b>December 31, 2013</b>                        | <b>153,028</b>                          | <b>2,154</b>                  | <b>155,182</b>                | <b>38,882</b>   | <b>2,638.8</b>          | <b>633,864</b>  |
| Discoveries                                     | -                                       | -                             | -                             | -               | -                       | -               |
| Extensions and Improved Recovery <sup>(1)</sup> | 9,204                                   | -                             | 9,204                         | 6,024           | 392.3                   | 80,619          |
| Technical Revisions                             | 659                                     | 107                           | 767                           | (1,207)         | 62.2                    | 9,923           |
| Acquisitions                                    | 531                                     | -                             | 531                           | 20              | 1.1                     | 729             |
| Dispositions                                    | (70)                                    | (19)                          | (89)                          | (1)             | (51.7)                  | (8,701)         |
| Economic Factors                                | (469)                                   | (7)                           | (476)                         | (286)           | (13.5)                  | (3,009)         |
| Production                                      | (12,880)                                | (203)                         | (13,083)                      | (2,978)         | (147.7)                 | (40,677)        |
| <b>December 31, 2014</b>                        | <b>150,003</b>                          | <b>2,032</b>                  | <b>152,035</b>                | <b>40,454</b>   | <b>2,881.6</b>          | <b>672,748</b>  |

Note:

- (1) Reserve additions for Infill Drilling, Extensions and Improved Recovery are combined and reported as 'Extensions and Improved Recovery'.

## 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:

### Future Development Costs

| Year                          | Proved Reserves (\$MM) | Proved Plus Probable Reserves (\$MM) |
|-------------------------------|------------------------|--------------------------------------|
| 2015                          | 557.8                  | 689.3                                |
| 2016                          | 475.6                  | 679.4                                |
| 2017                          | 385.8                  | 636.0                                |
| 2018                          | 284.7                  | 469.2                                |
| 2019                          | 154.6                  | 234.8                                |
| Remainder                     | 219.2                  | 928.0                                |
| Total: Undiscounted           | 2,077.7                | 3,636.7                              |
| Total: Discounted at 10%/year | 1,660.4                | 2,660.6                              |

We expect to fund the development costs of the reserves through a combination of sources including funds from operations, proceeds from ARC's DRIP, reduced funding for the payment of cash dividends resulting from ARC's SDP, proceeds from property dispositions, debt capacity, and if necessary, the equity issuance of Common Shares.

Changes in forecast future development capital occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved plus probable undeveloped reserves on production. Undiscounted future development costs ("FDC") for proved plus probable undeveloped reserves increased to \$3.6 billion at year-end 2014 from \$3.3 billion at year-end 2013. The increase in FDC is mainly attributed to reserve adding capital for future development of NE BC Montney.

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 funds from operations.

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.

## 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 tables disclose by each product type the volumes of proved and probable undeveloped reserves that were first attributed by GLJ in each of the most recent three financial years and, in the aggregate, before that time.

## Proved Undeveloped Reserves

|       | Light & Medium Oil (Mbbbl) |                   | Heavy Oil (Mbbbl) |                   | Natural Gas Liquids (Mbbbl) |                   | Natural Gas (MMcf) |                   | Total (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 | 12,768                     | 12,768            | -                 | -                 | 8,122                       | 8,122             | 719,277            | 719,277           | 140,770          | 140,770           |
| 2012  | 5,572                      | 14,743            | -                 | -                 | 915                         | 9,375             | 43,103             | 760,334           | 13,671           | 150,840           |
| 2013  | 7,008                      | 17,690            | 105               | 105               | 860                         | 9,462             | 22,524             | 785,299           | 11,727           | 158,139           |
| 2014  | 4,282                      | 15,191            | -                 | 105               | 1,869                       | 8,833             | 131,937            | 769,568           | 28,140           | 152,390           |

## Probable Undeveloped Reserves

|       | Light & Medium Oil (Mbbbl) |                   | Heavy Oil (Mbbbl) |                   | Natural Gas Liquids (Mbbbl) |                   | Natural Gas (MMcf) |                   | Total (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 | 10,976                     | 10,976            | -                 | -                 | 10,667                      | 10,667            | 787,242            | 787,242           | 152,850          | 152,850           |
| 2012  | 7,946                      | 18,581            | 61                | 61                | 1,638                       | 13,314            | 54,306             | 890,847           | 18,696           | 180,431           |
| 2013  | 7,466                      | 17,950            | -                 | 42                | 2,573                       | 13,054            | 68,905             | 943,665           | 21,523           | 188,324           |
| 2014  | 4,955                      | 19,599            | -                 | 42                | 3,723                       | 13,837            | 220,737            | 1,061,276         | 45,467           | 210,357           |

As of December 31, 2014, undeveloped reserves represented 40 per cent of total proved reserves and 54 per cent of proved plus probable reserves. Over 88 per cent of the proved plus probable undeveloped reserves are located in the Northeast BC core area. We have planned a program for the development of a portion of the undeveloped reserves in 2015 and 2016, focusing on the Sunrise, Dawson and Parkland/Tower areas.

The pace of development of the proved and probable undeveloped reserves is influenced by many factors, including the outcomes of the yearly drilling and reservoir evaluations, the price for oil and natural gas, and a variety of economic factors and conditions.

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 undeveloped reserves assigned to the NE BC Montney. Sophisticated and expensive technology and large capital expenditures are required to bring these undeveloped reserves into production. In addition, see "*Other Oil and Gas Information – Contingent Resource Estimates*" for a discussion of risks which relate to the recovery of additional reserves and contingencies that prevent resources from being classified as reserves.

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

## Other Oil and Gas Information

### Core Areas

The following is a description of our principal oil and natural gas core areas as at December 31, 2014. Reserves amounts are stated at December 31, 2014, 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, 2014, and information in respect of production is for the year ended December 31, 2014 except where indicated otherwise. Due to the fact that we have been active at acquiring additional interests in our core areas (and divesting assets in our non-core properties), the working interest in gross/net acres and wells at December 31, 2014 may not directly correspond to the stated production for the year, which only includes production after (or up to) the date the interests were acquired (or divested) by us. The estimate of reserves for individual properties and/or core areas may not reflect the same confidence level as estimates for all properties, due to the effects of aggregation.

All of the core areas described below are located in the Western Canadian Sedimentary Basin and within the Canadian provinces of British Columbia, Alberta, Saskatchewan or Manitoba. Except as set forth under the heading "Statement of Reserves Data and Other Oil and Gas Information – Undeveloped Reserves", there are no other material districts to which reserves have been attributed that are capable of producing but which are not producing at December 31, 2014 and there are no material statutory or mandatory relinquishments, surrenders, back-ins or changes in ownership provisions. When determining gross and net acreage for two or more lease agreements covering the same lands but different rights, the acreage is reported for each lease agreement.

### 2014 Company Gross Reserves and Company Gross Production

| Core Area                  | Light & Medium Crude Oil <sup>(1)</sup><br>(bbl/d) | Heavy Oil <sup>(1)</sup><br>(bbl/d) | Natural Gas <sup>(1)</sup><br>(MMcf/d) | Natural Gas Liquids <sup>(1)</sup><br>(bbl/d) | Total Oil Equivalent Production <sup>(1)</sup><br>(boe/d) | Proved Reserves<br>(Mboe) | Proved Plus Probable Reserves<br>(Mboe) | (%)          |
|----------------------------|--|-------------------------------------|--|---|---|---------------------------|---|--------------|
| NE British Columbia        | 3,384  | -                                   | 296.3                                  | 4,882   | 57,653  | 234,721                   | 462,601                                 | 68.8         |
| Northern Alberta           | 9,520  | 17                                  | 68.5                                   | 2,306   | 23,260  | 44,365                    | 69,794                                  | 10.4         |
| Pembina                    | 8,097  | 107                                 | 11.9                                   | 564   | 10,746  | 37,856                    | 52,546                                  | 7.8          |
| South Central Alberta      | 3,847  | 433                                 | 26.9                                   | 285   | 9,041   | 32,580                    | 42,957                                  | 6.4          |
| SE Saskatchewan & Manitoba | 10,440   | -                                   | 1.1                                    | 123   | 10,743  | 32,541                    | 44,850                                  | 6.7          |
| <b>Total</b>               | <b>35,288</b>                                      | <b>556</b>                          | <b>404.6</b>                           | <b>8,160</b>                                  | <b>111,444</b>  | <b>382,063</b>            | <b>672,748</b>                          | <b>100.0</b> |

Note:

- (1) Production volumes as disclosed above are "gross production" which is our interest (operated and non-operated) in production before deduction of royalties and without including any royalty interests to us. These volumes differ from the "company interest production" volumes disclosed in this Annual Information Form under "ARC Resources Ltd. - Development of our Business" and "Statement of Reserves Data and Other Oil and Gas Information – Production History" as well as in our audited consolidated financial statements for the year ended December 31, 2014 and the related Management's Discussion and Analysis which is our interest (operated and non-operated) in production before deduction of royalties and including royalty interests.



### *NE British Columbia*

ARC's assets in northeast British Columbia are predominantly located in the Montney resource play. The Montney is recognized as one of the best tight gas plays in North America with both dry and liquids-rich gas as well as a light oil fairway where ARC's Tower assets are located. ARC was an early entrant in the Montney, and pioneered the use of multi-stage fracturing for horizontal completions; a technology that has proved instrumental in unlocking the play. Today, ARC is one of the largest operators in the region and has expanded its land holdings to 529 net Montney sections in BC. The Montney is a key growth area with significant potential for continued reserves and production additions. In 2014, the gross proven plus probable reserves assigned by GLJ for northeast British Columbia were 463 MMboe or 69 per cent of the total proven plus probable reserves of the Corporation. The GLJ Report estimates the drilling of 398 proved undeveloped and probable locations will be needed to achieve production of these reserves.

During 2014, ARC continued the successful development and delineation of various properties within this core area spending \$477 million or 50 per cent of its' 2014 capital program (excluding land purchases) in this area. ARC has an average operating ownership of 88 per cent in approximately 191,462 gross hectares (169,346 net hectares). Key operating areas include Dawson, Parkland/Tower, Sunrise, Septimus and Attachie. ARC drilled 59 gross operated wells in 2014 with a working interest of approximately 100 per cent.

During the fourth quarter of 2013, ARC successfully and safely commissioned its new Parkland/Tower gas processing and liquids handling facility. Due to strong production results from this area, ARC is expanding its liquids handling facility at Parkland/Tower from 5,000 barrels per day to 10,000 barrels per day by the end of 2015. ARC is also proceeding with the construction of an ARC operated 60 MMcf per day gas processing facility at Sunrise which is scheduled to be commissioned during the fourth quarter of 2015. The project is on schedule and on budget and the fourth quarter of 2014 saw considerable activity with major equipment arriving on site. In addition, ARC is moving forward in 2015 with the preliminary planning, design and permitting for a 90 MMcf per day gas processing facility and associated liquids handling facility at Dawson.

### *Northern Alberta*

ARC's holdings in northern Alberta are characterized by long-life reserves and have significant potential for continued growth and development. ARC holds a total of 461 sections of Montney land in this core area. ARC's Ante Creek property, where ARC holds 336 net sections, is located within the oil prone window of the Montney formation and produces a mixture of oil, natural gas and natural gas liquids.

This district was a focus in 2014 where \$192 million or 20 per cent of the 2014 capital program (excluding land purchases) was spent, primarily at Ante Creek, with 40 gross operated wells drilled. In the Northern Alberta area, the Corporation has an average operating ownership of 76 per cent in approximately 332,919 gross hectares (254,229 net hectares). In 2014, GLJ assigned gross proved reserves of 44 MMboe and gross proved plus probable reserves of 70

MMboe of oil, natural gas and natural gas liquids to the Northern Alberta core area, representing 10 per cent of ARC's total gross proved plus probable reserves. The GLJ Report estimates the drilling of 74 operated proved undeveloped and probable locations will be needed to achieve production of these reserves.

ARC plans to continue to delineate this large, prospective land base and continues to assess infrastructure requirements in conjunction with future development plans for Ante Creek.

#### *Pembina*

ARC has been a core owner in the area since its inception in 1996 and today is one of the largest operators in the area. The field is characterized by its long reserve life, high netback high quality oil, and proximity to refining facilities. In this area, ARC focuses on reservoir management and maximizing recovery through optimization of the water flood. The application of horizontal technology in the region is reviving this 60 year old asset. Key properties held by ARC in the area include the Berrymoor Cardium Unit (73.3 per cent unit interest), the Lindale Cardium Unit (55.3 per cent unit interest), MIPA (99.6 per cent working interest) and the North Pembina Cardium Unit (47.1 per cent unit interest).

During 2014, ARC spent \$117 million or approximately 12 per cent of the 2014 capital program (excluding land purchases) in this area and maintained production at an average of approximately 12,100 boe per day, drilling a total of 38 gross operated Cardium horizontal oil wells. ARC has an average operating ownership of 74 per cent in approximately 67,930 gross hectares (50,375 net hectares). In 2014, GLJ assigned gross proved reserves of 38 MMboe and gross proved plus probable reserves of 53 MMboe of oil, natural gas and natural gas liquids to this core area, representing eight per cent of ARC's total gross proved plus probable reserves. The GLJ Report estimates the drilling of 79 operated proved undeveloped and probable locations will be needed to achieve production of these reserves.

ARC's deliberate, paced development program at Pembina is aimed at managing production declines in this area, while generating significant free cash flow. ARC will continue with work on waterflood management at Pembina in 2015 to optimize reservoir recoveries.

#### *South Central Alberta*

ARC's south central Alberta assets produce shallow gas and medium to light crude oil. ARC's assets in this core area reach from Redwater, Alberta to Gull Lake, Saskatchewan encompassing one of Canada's largest historical shallow gas producing regions. This area provides ARC with stable production characterized as low decline and low risk.

During 2014, ARC spent \$29 million or approximately three per cent of the 2014 capital program (excluding land purchases) in this area and has an average operating ownership of 73 per cent in this area in approximately 175,829 gross hectares (128,258 net hectares). GLJ assigned gross proved reserves of 33 MMboe and gross proved plus probable reserves of 43 MMboe of oil, natural gas and natural gas liquids to the South Central AB core area, representing six per cent of ARC's total gross proved plus probable reserves. The GLJ Report estimates the drilling of 69 operated proved undeveloped and probable locations will be needed to achieve the production of these reserves.

Redwater is the largest property by production in the area at approximately 3,400 boe per day during 2014. Oil and solution gas are processed at a central operated facility. During 2014, 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<sub>2</sub> flooding and if incremental oil can be mobilized and recovered. The CO<sub>2</sub> injection phase of the pilot has been completed, while the observation of producing wells continues. Prior to commercial operations, large amounts of CO<sub>2</sub> 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.

#### *SE Saskatchewan & Manitoba*

ARC's southeast Saskatchewan and Manitoba properties produce high netback, light crude oil. Located in the Williston basin, ARC's assets span over 350 kilometres from Landscape, Saskatchewan to Goodlands, Manitoba. Key properties held by ARC in the area include Loughheed, the Weyburn Unit (6.9 per cent unit interest), the Midale Unit (15.5 per cent unit interest), Oungre and Goodlands. ARC has excellent exposure to enhanced oil recovery ("EOR") projects at the Weyburn Unit and the Midale Unit CO<sub>2</sub> floods.

During 2014, ARC spent \$111 million or approximately 12 per cent of the 2014 capital program (excluding land purchases) in this area. The 2014 capital spend in this region was concentrated at the Oungre and Skinner Lake properties in southeastern Saskatchewan and the Goodlands property located in southwestern Manitoba. ARC has an average operating ownership of 80 per cent in approximately 70,195 gross hectares (56,194 net hectares) in this area.

GLJ assigned gross proved reserves of 33 MMboe and gross proved plus probable reserves of 45 MMboe of oil, natural gas and natural gas liquids to this area, representing seven per cent of ARC's total gross proved plus probable reserves. The GLJ Report estimates the drilling of 69 operated proved undeveloped and probable locations will be needed to achieve production of these reserves.

### Economic Contingent Resource Estimates

ARC engaged GLJ to provide an updated evaluation of, among other things, our Economic Contingent Resources (as defined below) effective December 31, 2014, for our working interest in our northeast British Columbia Montney properties, including lands at Pouce Coupe across the provincial border, all of which will be referred to as "NE BC" for purposes of this section. ARC owns an average 92 per cent working interest in 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, 2015 forecast pricing. See "*Statement of Reserves Data and Other Oil and Gas Information - Forecast Prices and Costs*".

**The Economic Contingent Resources should not be confused with reserves and readers should review the definitions and notes set forth below. Actual crude oil, 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.**

|                              | Best Estimate <sup>(3)</sup> |
|------------------------------|------------------------------|
| Natural Gas (Tcf)            | 4.9                          |
| Natural Gas Liquids (MMbbls) | 143.2                        |
| Oil (MMbbls)                 | 35.2                         |

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. The resources evaluation was effective December 31, 2014 based on GLJ's January 1, 2015 forecast pricing and costs.
- (2) Based on the GLJ Report and effective as of December 31, 2014 and based on Gross Volumes.
- (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.

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, natural gas liquids, and oil prices that would curtail the economics of development, 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 primary contingencies that prevent the Economic Contingent Resources from being classified as reserves are for Management and the Board to ascertain commercial production rates, then develop firm plans, including timing, infrastructure, and the commitment of capital. Additional contingencies are related to the current lack of infrastructure, mostly gas processing but in some cases transportation, required to develop the resources in a relatively quick time frame. As continued delineation occurs, some Economic Contingent Resources are expected to be re-classified to reserves.

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, natural gas liquids

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

### Oil And Gas Wells

The following tables set forth the number and status of wells in which we had a working interest as at December 31, 2014.

| By Core Area               | Oil Wells    |              |               |            | Natural Gas Wells |              |               |            |
|----------------------------|--------------|--------------|---------------|------------|-------------------|--------------|---------------|------------|
|                            | Producing    |              | Non-Producing |            | Producing         |              | Non-Producing |            |
|                            | Gross        | Net          | Gross         | Net        | Gross             | Net          | Gross         | Net        |
| NE British Columbia        | 61           | 57           | 15            | 14         | 378               | 350          | 37            | 28         |
| Northern Alberta           | 979          | 424          | 390           | 120        | 512               | 128          | 193           | 72         |
| Pembina                    | 1,296        | 728          | 300           | 116        | 56                | 13           | 15            | 2          |
| South Central Alberta      | 653          | 567          | 109           | 99         | 2,463             | 1,690        | 146           | 52         |
| SE Saskatchewan & Manitoba | 2,477        | 993          | 297           | 68         | -                 | -            | -             | -          |
| <b>Total</b>               | <b>5,466</b> | <b>2,769</b> | <b>1,111</b>  | <b>417</b> | <b>3,409</b>      | <b>2,180</b> | <b>391</b>    | <b>154</b> |

| By Province      | Oil Wells    |              |               |            | Natural Gas Wells |              |               |            |
|------------------|--------------|--------------|---------------|------------|-------------------|--------------|---------------|------------|
|                  | Producing    |              | Non-Producing |            | Producing         |              | Non-Producing |            |
|                  | Gross        | Net          | Gross         | Net        | Gross             | Net          | Gross         | Net        |
| Alberta          | 2,832        | 1,695        | 791           | 333        | 3,031             | 1,831        | 342           | 123        |
| British Columbia | 61           | 57           | 15            | 14         | 378               | 350          | 37            | 28         |
| Saskatchewan     | 719          | 238          | 13            | 3          | -                 | -            | -             | -          |
| Manitoba         | 1,854        | 779          | 292           | 67         | -                 | -            | 12            | 3          |
| <b>Total</b>     | <b>5,466</b> | <b>2,769</b> | <b>1,111</b>  | <b>417</b> | <b>3,409</b>      | <b>2,180</b> | <b>391</b>    | <b>154</b> |

## Properties with no Attributable Reserves

The following table sets out by district our undeveloped land holdings as at December 31, 2014.

### *Undeveloped Hectares*

|                            | <b>Gross</b> | <b>Net</b> |
|----------------------------|--------------|------------|
| NE British Columbia        | 123,671      | 108,416    |
| Northern Alberta           | 217,907      | 160,207    |
| Pembina                    | 46,848       | 12,195     |
| South Central Alberta      | 35,183       | 25,016     |
| SE Saskatchewan & Manitoba | 31,099       | 25,329     |
| Total                      | 454,708      | 331,163    |

Undeveloped hectares are lands that have not been assigned reserves; however, in certain of our undeveloped lands, reserves may have been assigned in shallower formations.

We currently have no material work commitments on these lands in 2015. There are no material expiries in our core holdings in 2015.

### **Forward Contracts**

We are exposed to market risks resulting from fluctuations in commodity prices, power prices, foreign exchange rates and interest rates in the normal course of operations. ARC maintains a risk management program to reduce the volatility of revenues, increase the certainty of funds from operations, and to protect acquisition and development economics.

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, including counterparties among our lending syndicate, and by monitoring their ongoing credit risks.

ARC's risk management program is governed by certain guidelines approved by the Board of Directors. These guidelines permit hedging up to a maximum of 55 per cent of forecasted production on a boe basis for up to two years with a maximum of 70 per cent for any one commodity. Specifically for natural gas, the guidelines permit additional hedging of 25 per cent of forecasted production beyond year two and up to five years. Further to these authorizations, the Board of Directors may approve hedging higher percentages of forecasted production or longer term hedging transactions to mitigate risks relating to, and protecting the economics of major capital expenditures, including acquisitions. The Risk Committee of the Board of Directors reviews policies, procedures and provides oversight to management in the areas of financial and business risks including activities related to our hedging program.

A summary of financial and physical contracts in respect of hedging activities can be found in Note 15 "*Financial Instruments and Market Risk Management*" to our audited consolidated financial statements for the year ended December 31, 2014 and in the section under the heading "*Risk Management*" in our Management's Discussion and Analysis for the year ended December 31, 2014 which have been filed on our SEDAR profile at [www.sedar.com](http://www.sedar.com), and both of which the note and section are incorporated in this Annual Information Form by reference.

## 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 & Reclamation*

| <b>Costs escalated at 2.0%</b> | <b>Undiscounted<br/>(\$MM)</b> | <b>Discounted at 10%<br/>(\$MM)</b> |
|--------------------------------|--------------------------------|-------------------------------------|
| Total as at December 31, 2014  | 1,559.9                        | 82.3                                |
| Anticipated to be paid in 2015 | 13.3                           | 12.1                                |
| Anticipated to be paid in 2016 | 3.6                            | 3.0                                 |
| Anticipated to be paid in 2017 | 3.8                            | 2.8                                 |

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 7,132 net wells that will require abandonment and/or reclamation over the next 60 years with the majority of payments being made in years 2063 to 2074. This net well count includes producing and non-producing oil wells, producing and non-producing natural gas wells, injection and disposal wells and wells that have been abandoned but not yet full reclaimed. 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 \$1,559.9 million calculated by escalating costs at two per cent per year (reflected in our audited consolidated financial statements as an asset retirement obligation of \$616.1 million calculated by escalating costs at two per cent per year and discounting at a liability-specific risk-free rate of approximately 2.3 per cent). For more information, see Note 13 of our audited consolidated financial statements for the year ended December 31, 2014 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 our SEDAR profile at [www.sedar.com](http://www.sedar.com). During 2014, \$23 million (\$18.5 million for 2013) of actual expenditures were incurred on abandonment and reclamation activities.

ARC's estimated liability associated with well, pipeline, and facility abandonment and reclamation costs, which was not included by GLJ in estimating future net revenue in the GLJ Report, is \$1,244.9 million (escalating costs at two per cent and undiscounted) and \$27.3 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.

We have committed to a restricted reclamation trust associated with the acquisition of the Redwater property pursuant to which ARC 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. In accordance with the fund agreement, ARC has contributed total funds of \$44.7 million to the restricted reclamation fund as at December 31, 2014. Contributions to the fund will continue at a declining rate through 2055. The balance of the restricted reclamation fund was \$35.2 million at December 31, 2014.

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 Alberta Energy Regulator.

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.

## Tax Horizon

We expect to allocate our funds from operations towards a portion of capital expenditures, periodic debt repayments, site reclamation expenditures, potential net acquisitions of land and production, and cash payments to Shareholders in the form of dividends. 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 \$2.5 billion of income tax pools for federal tax purposes as at December 31, 2014. ARC recognized current income taxes in 2014. For 2015 ARC expects to recognize current income taxes, however this will be dependent on the commodity price environment and capital spending.

## 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, 2014:

### 2014 Capital Expenditures

|  | NE British<br>Columbia<br>(\$MM) | Northern<br>Alberta<br>(\$MM) | Pembina<br>(\$MM) | South<br>Central Alberta<br>(\$MM) | SE Sask./<br>Manitoba<br>(\$MM) | Corporate<br>(\$MM) | Total<br>(\$MM) |
|--|----------------------------------|-------------------------------|-------------------|------------------------------------|---------------------------------|---------------------|-----------------|
| Property Acquisition<br>(Disposition) Costs,<br>Net <sup>(1)</sup> |                                  |                               |                   |                                    |                                 |                     |                 |
| Proved Properties  | 20.5                             | 34.1                          | 13.4              | (33.8)                             | (4.5)                           | -                   | 29.7            |
| Undeveloped<br>Properties  | 1.9                              | 2.6                           | -                 | -                                  | -                               | -                   | 4.5             |
| Exploration Costs <sup>(2)</sup>                                   | 33.6                             | (0.5)                         | -                 | 10.2                               | 6.1                             | -                   | 49.4            |
| Development Costs <sup>(3)</sup>                                   | 466.2                            | 210.6                         | 117.5             | 18.8                               | 105.9                           | 20.5                | 939.5           |
| Corporate Capital<br>Costs <sup>(4)</sup>                          | -                                | -                             | -                 | -                                  | -                               | 18.9                | 18.9            |
| <b>Total</b>   | <b>522.2</b>                     | <b>246.8</b>                  | <b>130.9</b>      | <b>(4.8)</b>                       | <b>107.5</b>                    | <b>39.4</b>         | <b>1,042.0</b>  |

#### Notes:

- (1) Represents acquisition costs net of dispositions and property swaps. Acquisition value is net of post-closing adjustments. Disposition value represents proceeds and adjustments to proceeds from divestitures.
- (2) Represents asset additions that have been determined by management to be in the exploration and evaluation stage and includes costs of land acquired (\$1.4 million).
- (3) Represents additions to oil and gas development and production assets and administrative assets and includes costs of land acquired (\$60.9 million).
- (4) Represents administrative assets allocated at the corporate level.

## Exploration and Development Activities

The following tables set forth the gross and net exploratory and development wells that we participated in during the year ended December 31, 2014:

| By Core Area                  | Exploratory Wells <sup>(1)</sup> |            | Development Wells <sup>(1)</sup> |              | Total <sup>(1)</sup> |              |
|-------------------------------|----------------------------------|------------|----------------------------------|--------------|----------------------|--------------|
|                               | Gross                            | Net        | Gross                            | Net          | Gross                | Net          |
| NE British Columbia           | 1.0                              | 1.0        | 60.0                             | 59.0         | 61.0                 | 60.0         |
| Northern Alberta              | 1.0                              | 1.0        | 45.0                             | 39.5         | 46.0                 | 40.5         |
| Pembina                       | -                                | -          | 38.0                             | 30.8         | 38.0                 | 30.8         |
| South Central Alberta         | 1.0                              | 1.0        | 2.0                              | 2.0          | 3.0                  | 3.0          |
| SE Saskatchewan &<br>Manitoba | -                                | -          | 101.0                            | 48.9         | 101.0                | 48.9         |
| <b>Total</b>                  | <b>3.0</b>                       | <b>3.0</b> | <b>246.0</b>                     | <b>180.2</b> | <b>249.0</b>         | <b>183.2</b> |

| By Well Type       | Exploratory Wells <sup>(1)</sup> |            | Development Wells <sup>(1)</sup> |              | Total <sup>(1)</sup> |              |
|--------------------|----------------------------------|------------|----------------------------------|--------------|----------------------|--------------|
|                    | Gross                            | Net        | Gross                            | Net          | Gross                | Net          |
| Light & Medium Oil | 2.0                              | 2.0        | 188.0                            | 131.3        | 190.0                | 133.3        |
| Heavy Oil          | -                                | -          | -                                | -            | -                    | -            |
| Natural Gas        | 1.0                              | 1.0        | 53.0                             | 48.5         | 54.0                 | 49.5         |
| Service            | -                                | -          | 5.0                              | 0.3          | 5.0                  | 0.3          |
| Dry                | -                                | -          | -                                | -            | -                    | -            |
| <b>Total</b>       | <b>3.0</b>                       | <b>3.0</b> | <b>246.0</b>                     | <b>180.2</b> | <b>249.0</b>         | <b>183.2</b> |

Note:

(1) Number of wells based on rig release dates.

The 2015 capital program is focused on creating value by directing capital to a mix of crude oil, liquids-rich gas and natural gas opportunities that continue to provide profitable returns at low commodity prices. The Corporation's 2015 capital budget includes investment in strategic infrastructure at Sunrise and front-end engineering and government applications for the Dawson liquids-rich gas processing facility which will set the stage for future growth in key areas in the Montney region. Capital will also be dedicated towards advancing the lower Montney development at Dawson and Pouce Coupe as well as expanding its liquids handling facility at Parkland/Tower from 5,000 barrels per day to 10,000 barrels per day.

Our capital program was placed under review in February 2015 with the expectation of providing revised guidance with our first quarter 2015 results. Given the volatility in commodity prices, it will be subject to variation throughout the year depending upon prices for oil and natural gas and other factors 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 tables set out the GLJ forecast of the volume of production estimated for the year ended December 31, 2015 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*".

| TOTAL PROVED        |                            |               |                   |            |                     |                |                             |              |                |               |
|---------------------|----------------------------|---------------|-------------------|------------|---------------------|----------------|-----------------------------|--------------|----------------|---------------|
|                     | Light & Medium Oil (bbl/d) |               | Heavy Oil (bbl/d) |            | Natural Gas (Mcf/d) |                | Natural Gas Liquids (bbl/d) |              | Total (boe/d)  |               |
|                     | Gross                      | Net           | Gross             | Net        | Gross               | Net            | Gross                       | Net          | Gross          | Net           |
| Dawson              | -                          | -             | -                 | -          | 137,325             | 116,174        | 680                         | 582          | 23,567         | 19,944        |
| Other Properties    | 30,259                     | 26,889        | 539               | 607        | 249,182             | 225,937        | 5,938                       | 4,860        | 78,267         | 70,012        |
| <b>Total Proved</b> | <b>30,259</b>              | <b>26,889</b> | <b>539</b>        | <b>607</b> | <b>386,507</b>      | <b>342,111</b> | <b>6,618</b>                | <b>5,442</b> | <b>101,834</b> | <b>89,956</b> |

| TOTAL PROBABLE        |                            |              |                   |           |                     |               |                             |            |               |               |
|-----------------------|----------------------------|--------------|-------------------|-----------|---------------------|---------------|-----------------------------|------------|---------------|---------------|
|                       | Light & Medium Oil (bbl/d) |              | Heavy Oil (bbl/d) |           | Natural Gas (Mcf/d) |               | Natural Gas Liquids (bbl/d) |            | Total (boe/d) |               |
|                       | Gross                      | Net          | Gross             | Net       | Gross               | Net           | Gross                       | Net        | Gross         | Net           |
| Dawson                | -                          | -            | -                 | -         | 15,764              | 14,034        | 78                          | 70         | 2,705         | 2,409         |
| Other Properties      | 3,010                      | 2,608        | 12                | 15        | 33,875              | 31,356        | 886                         | 767        | 9,554         | 8,617         |
| <b>Total Probable</b> | <b>3,010</b>               | <b>2,608</b> | <b>12</b>         | <b>15</b> | <b>49,639</b>       | <b>45,390</b> | <b>964</b>                  | <b>837</b> | <b>12,259</b> | <b>11,026</b> |

| TOTAL PROVED PLUS PROBABLE        |                            |               |                   |            |                     |                |                             |              |                |                |
|-----------------------------------|----------------------------|---------------|-------------------|------------|---------------------|----------------|-----------------------------|--------------|----------------|----------------|
|                                   | Light & Medium Oil (bbl/d) |               | Heavy Oil (bbl/d) |            | Natural Gas (Mcf/d) |                | Natural Gas Liquids (bbl/d) |              | Total (boe/d)  |                |
|                                   | Gross                      | Net           | Gross             | Net        | Gross               | Net            | Gross                       | Net          | Gross          | Net            |
| Dawson                            | -                          | -             | -                 | -          | 153,089             | 130,208        | 758                         | 652          | 26,272         | 22,353         |
| Other Properties                  | 33,269                     | 29,497        | 551               | 622        | 283,058             | 257,293        | 6,824                       | 5,628        | 87,821         | 78,628         |
| <b>Total Proved Plus Probable</b> | <b>33,269</b>              | <b>29,497</b> | <b>551</b>        | <b>622</b> | <b>436,146</b>      | <b>387,500</b> | <b>7,582</b>                | <b>6,279</b> | <b>114,093</b> | <b>100,981</b> |

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:

| Production History                          | Quarter Ended 2014 |         |         |         | Year Ended 2014 |
|---|--------------------|---------|---------|---------|-----------------|
|   | Mar 31             | June 30 | Sept 30 | Dec 31  |                 |
| Average Daily Production <sup>(1)</sup>     |                    |         |         |         |                 |
| Light and Medium Crude Oil (bbl/d)          | 36,530             | 34,361  | 34,713  | 36,276  | 35,467          |
| Heavy Oil (bbl/d)                           | 948                | 956     | 1,158   | 1,166   | 1,058           |
| Gas (MMcf/d)                                | 369.6              | 397.2   | 424.5   | 432.1   | 406.1           |
| Natural Gas Liquids (bbl/d) <sup>(2)</sup>  | 6,630              | 8,641   | 8,918   | 8,523   | 8,185           |
| Condensate (bbl/d)                          | 2,887              | 4,462   | 3,862   | 3,448   | 3,667           |
| NGLs (bbl/d) <sup>(3)</sup>                 | 3,743              | 4,179   | 5,056   | 5,075   | 4,518           |
| Total (boe/d)                               | 105,699            | 110,165 | 115,530 | 117,986 | 112,387         |
| Average Net Production Prices Received      |                    |         |         |         |                 |
| Light and Medium Crude Oil (\$/bbl)         | 96.14              | 102.71  | 93.83   | 72.90   | 91.17           |
| Heavy Oil (\$/bbl)                          | 74.01              | 81.36   | 78.55   | 59.71   | 72.95           |
| Gas (\$/Mcf)                                | 5.60               | 4.99    | 4.46    | 4.15    | 4.76            |
| Natural Gas Liquids (\$/bbl) <sup>(2)</sup> | 71.00              | 72.67   | 63.83   | 49.42   | 63.81           |
| Condensate (\$/bbl)                         | 100.11             | 103.72  | 95.55   | 74.04   | 93.81           |
| NGLs (\$/bbl) <sup>(3)</sup>                | 48.54              | 39.51   | 39.61   | 32.69   | 39.45           |
| Total (\$/boe) <sup>(4)</sup>               | 57.96              | 56.56   | 50.36   | 41.83   | 51.38           |

| Production History                          | Quarter Ended 2014 |         |         |        | Year       |
|---|--------------------|---------|---------|--------|------------|
|   | Mar 31             | June 30 | Sept 30 | Dec 31 | Ended 2014 |
| <b>Royalties Paid</b>                       |                    |         |         |        |            |
| Light and Medium Crude Oil (\$/bbl)         | 14.01              | 16.47   | 16.35   | 11.97  | 14.65      |
| Heavy Oil (\$/bbl)                          | 4.32               | 6.28    | 5.14    | 4.32   | 4.99       |
| Gas (\$/Mcf)                                | 0.78               | 0.57    | 0.39    | 0.39   | 0.52       |
| Natural Gas Liquids (\$/bbl) <sup>(2)</sup> | 12.62              | 9.96    | 8.60    | 8.44   | 9.72       |
| Condensate (\$/bbl)                         | 16.96              | 13.21   | 13.75   | 13.72  | 14.20      |
| NGLs (\$/bbl) <sup>(3)</sup>                | 9.26               | 6.48    | 4.67    | 4.85   | 6.08       |
| Total (\$/boe)                              | 8.41               | 8.02    | 7.05    | 5.77   | 7.26       |
| <b>Operating Expenses <sup>(5)(6)</sup></b> |                    |         |         |        |            |
| Light and Medium Crude Oil (\$/bbl)         | 13.94              | 16.40   | 15.21   | 14.46  | 14.94      |
| Heavy Oil (\$/bbl)                          | 18.13              | 15.73   | 15.57   | 13.27  | 15.54      |
| Gas (\$/Mcf)                                | 0.99               | 0.97    | 1.00    | 0.96   | 0.97       |
| Natural Gas Liquids (\$/bbl) <sup>(2)</sup> | 8.40               | 4.63    | 6.62    | 6.11   | 6.80       |
| Condensate (\$/bbl)                         | 8.22               | 2.04    | 6.56    | 6.18   | 6.58       |
| NGLs (\$/bbl) <sup>(3)</sup>                | 8.55               | 7.46    | 6.66    | 6.05   | 6.98       |
| Total (\$/boe)                              | 8.97               | 9.11    | 8.91    | 8.55   | 8.88       |
| <b>Transportation Paid</b>                  |                    |         |         |        |            |
| Light and Medium Crude Oil (\$/bbl)         | 2.91               | 2.83    | 2.74    | 3.39   | 2.97       |
| Heavy Oil (\$/bbl)                          | 0.84               | 0.84    | 0.58    | 0.62   | 0.71       |
| Gas (\$/Mcf)                                | 0.25               | 0.24    | 0.25    | 0.27   | 0.25       |
| Natural Gas Liquids (\$/bbl) <sup>(2)</sup> | 0.46               | 3.44    | 9.14    | 6.72   | 5.27       |
| Condensate (\$/bbl)                         | (0.24)             | 0.94    | 7.65    | 4.59   | 3.36       |
| NGLs (\$/bbl) <sup>(3)</sup>                | 0.99               | 6.11    | 10.28   | 8.17   | 6.82       |
| Total (\$/boe)                              | 1.91               | 2.02    | 2.44    | 2.51   | 2.23       |
| <b>(Loss)/Gain on Commodity Contracts</b>   |                    |         |         |        |            |
| Light and Medium Crude Oil (\$/bbl)         | (2.54)             | (3.87)  | (0.67)  | 7.24   | 0.12       |
| Heavy Oil (\$/bbl)                          | -                  | -       | -       | -      | -          |
| Gas (\$/Mcf)                                | (0.36)             | (0.37)  | (0.10)  | 0.02   | (0.19)     |
| Natural Gas Liquids (\$/bbl) <sup>(2)</sup> | -                  | -       | -       | -      | -          |
| Condensate (\$/bbl)                         | -                  | -       | -       | -      | -          |
| NGLs (\$/bbl) <sup>(3)</sup>                | -                  | -       | -       | -      | -          |
| Total (\$/boe)                              | (2.13)             | (2.53)  | (0.56)  | 2.29   | (0.65)     |
| <b>Netback Received <sup>(7)</sup></b>      |                    |         |         |        |            |
| Light and Medium Crude Oil (\$/bbl)         | 62.74              | 63.14   | 58.86   | 50.32  | 58.73      |
| Heavy Oil (\$/bbl)                          | 50.72              | 58.51   | 57.26   | 41.50  | 51.71      |
| Gas (\$/Mcf)                                | 3.22               | 2.84    | 2.72    | 2.55   | 2.83       |
| Natural Gas Liquids (\$/bbl) <sup>(2)</sup> | 49.52              | 54.64   | 39.47   | 28.15  | 42.02      |
| Condensate (\$/bbl)                         | 75.17              | 87.53   | 67.59   | 49.55  | 69.67      |
| NGLs (\$/bbl) <sup>(3)</sup>                | 29.74              | 19.46   | 18.00   | 13.62  | 19.57      |
| Total (\$/boe)                              | 36.54              | 34.88   | 31.40   | 27.29  | 32.36      |

Notes:

- (1) Before deduction of royalties and including royalty interests.
- (2) Natural Gas Liquids as defined by GLJ which includes condensate, butane, ethane and propane.
- (3) NGLs or natural gas liquids as defined by ARC in external reporting which includes butane, ethane and propane but excludes condensate.
- (4) Total average price received includes other income from standard business activities including interest earned on ARC's reclamation fund.
- (5) 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, condensate and natural gas liquids production.
- (6) Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.
- (7) Netbacks are calculated by subtracting royalties, operating expenses, transportation costs, and realized (losses)/gains on commodity contracts from revenues. Netbacks before hedging can be found in Table 17a "Netbacks" under the section Operating Netbacks of our Management's Discussion and Analysis for the year ended December 31, 2014 which has been filed on our SEDAR profile at [www.sedar.com](http://www.sedar.com).

The NE British Columbia, northern Alberta, Pembina, south central Alberta and southeast Saskatchewan & Manitoba core areas account for approximately 51 per cent, 21 per cent, 10 per cent, eight per cent and 10 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*".

## **Marketing Arrangements**

### ***Natural Gas***

During 2014, ARC continued its 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 2014 was \$4.76 per Mcf before hedging as compared to \$3.45 per Mcf before hedging for 2013. This price was achieved with a portfolio mix that on average through the year received AECO index based pricing for 77 percent, Western Canadian Station 2 index based pricing for 15 percent, and Chicago index pricing for eight percent 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 2014 was comprised of approximately 58 per cent light quality crude oil (greater than 35° API), 21 per cent medium quality crude oil (25° to 35° API), three per cent heavy quality crude (less than 25° API) and 18 per cent condensate and natural gas liquids.

During 2014, our average sales prices were \$91.17 per bbl for light and medium crude oil, \$72.95 per bbl for heavy crude oil and \$63.81 per bbl for natural gas liquids including free condensate; these prices compare to 2013 prices of \$89.44 per bbl for light and medium crude oil, \$69.00 per bbl for heavy crude oil and \$61.99 per bbl for natural gas liquids including free condensate.

During 2014, increases in Canadian and United States oil supply continued to place pressure on downstream pipeline and refinery infrastructure. ARC is strategically aligned with its crude oil purchasers which allowed us to be protected against varying degrees of price volatility in the market. 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. The majority of ARC's natural gas liquids are sold on a multi-year contract until April 1, 2017, after which they will be sold on a 10 year agreement to coincide with new fractionation capacity coming online. The remaining volume is 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 319,438,651 Common Shares and no preferred shares are outstanding as at December 31, 2014.

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.

Any 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 periodically 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. ARC's long-term strategy is to target net debt to be between 1.0 to 1.5 times annualized funds from operations and less than 20 per cent of total capitalization over the long term (see Note (1) in the section "*ARC Resources Ltd. – Strategy*" in this Annual Information Form). The level of borrowing is assessed on a weekly basis by management and is subject to quarterly reviews by the Board of Directors of ARC Resources.

Our borrowings 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 repayment will be scheduled to the extent possible to minimize any income tax payable by ARC Resources.

As at December 31, 2014, we had credit facilities consisting of a Cdn\$1 billion, financial covenant based credit facility with a syndicate of major chartered banks, a Cdn\$40 million working capital facility with its agent bank, a Cdn\$15 million letter of credit facility with its agent bank, a Cdn\$25 million letter of credit facility with another major chartered bank and member of the syndicate, and US\$809.7 million and Cdn\$51.6 million of senior notes outstanding. An additional amount of US\$121.9 million of senior notes was available to be issued pursuant to a US\$350 million Master Shelf Agreement with a large insurance company (the "**Master Shelf**"). ARC had a net debt balance of Cdn\$1,255.9 million outstanding at December 31, 2014, comprised of Cdn\$1,074.8 million of long-term debt and a working capital deficit of Cdn\$181.1 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. On November 6, 2014, the credit facility was extended for another year at more favorable pricing terms than the existing facility. The current maturity date of the credit facility is November 6, 2018.

ARC Resources has the option to negotiate a rate and term and draw the remaining credit capacity pursuant to the Master Shelf at any time. This option was renewed on September 25, 2014 and expires on September 25, 2017. 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 outstanding were issued in 11 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 3.25 trailing twelve month net income before non-cash items, income tax 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, income tax 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 in this Annual Information Form under "*Material Contracts*" and have been filed on our SEDAR profile at [www.sedar.com](http://www.sedar.com). For more information, reference is made to Note 12 of our audited consolidated financial statements for the year ended December 31, 2014, which note is incorporated by reference in this Annual Information Form and is found on our SEDAR profile at [www.sedar.com](http://www.sedar.com).

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

### Stock Dividend Program and Dividend Reinvestment Plan

ARC has established a Stock Dividend Program (previously defined as the "SDP") which enables shareholders to receive dividends in the form of Common Shares of ARC in lieu of receiving a cash dividend on the dividend payment date. Common Shares issued under the SDP are issued at a three per cent discount to the prevailing market price, as defined under the SDP, with no broker fees or commissions. The SDP is generally available to most shareholders and is expected to provide many shareholders with Canadian income tax treatment that is more favourable than ARC's Distribution Reinvestment Plan (previously defined as the "DRIP") which is described below.

ARC has also established a DRIP which enables Canadian shareholders to have their dividends reinvested into additional Common Shares of ARC. Common Shares issued under the DRIP are issued at a three per cent discount to the prevailing market price (five per cent discount to the prevailing market price for dividend payment dates prior to September 15, 2014), as defined under the DRIP, with no broker fees or commissions.

Participation in the SDP or the DRIP is optional. Shareholders will continue to receive dividend payments in cash unless they choose to participate in the SDP or the DRIP.

### DIRECTORS AND EXECUTIVE OFFICERS

The name and municipality of residence, positions held and principal occupation of each director of ARC Resources as at December 31, 2014 are set out below.

| Directors   |  |   |
|---|--|---|
| Name and Municipality of Residence                        | Office Held and Time as Director <sup>(1)</sup>      | Principal Occupation  |
| Mac H. Van Wielingen<br>Calgary, Alberta, Canada          | Chairman of the Board and Director since May 3, 1996 | Independent Businessman                                       |
| John P. Dielwart<br>Calgary, Alberta, Canada              | Director since May 3, 1996                           | Vice-Chairman of ARC Financial Corporation                    |
| Fred J. Dymant<br>Calgary, Alberta, Canada                | Director since April 17, 2003                        | Independent Businessman                                       |
| Timothy J. Hearn<br>Calgary, Alberta, Canada              | Director since June 22, 2011                         | Independent Businessman                                       |
| James C. Houck<br>Calgary, Alberta, Canada                | Director since February 14, 2008                     | Independent Businessman                                       |
| Harold N. Kvisle<br>Calgary, Alberta Canada               | Director since May 20, 2009                          | President and Chief Executive Officer of Talisman Energy Inc. |
| Kathleen M. O'Neill<br>Toronto, Ontario, Canada           | Director since June 1, 2009                          | Independent Businesswoman                                     |
| Herbert C. Pinder, Jr.<br>Saskatoon, Saskatchewan, Canada | Director since January 1, 2006                       | Independent Businessman                                       |
| William G. Sembo<br>Calgary, Alberta, Canada              | Director since November 6, 2013                      | Independent Businessman                                       |
| Myron M. Stadnyk<br>Calgary, Alberta, Canada              | Director since January 1, 2013                       | President and Chief Executive Officer of ARC Resources        |

Note:

- (1) The term of each director is until the next annual meeting of ARC Resources, which is scheduled to be held on April 30, 2015.

The name and municipality of residence, position held and principal occupation of each officer of ARC Resources as at December 31, 2014 are set out below.

| <b>Officers</b>  |   |  |
|--|---|--|
| <b>Name and Municipality of Residence</b>                    | <b>Office Held</b>                                | <b>Principal Occupation</b>  |
| Myron M. Stadnyk<br>Calgary, Alberta, Canada                 | President and Chief Executive Officer             | President and Chief Executive Officer of ARC Resources                       |
| P. Van R. Dafoe<br>Calgary, Alberta, Canada                  | Senior Vice President and Chief Financial Officer | Senior Vice President and Chief Financial Officer of ARC Resources           |
| Terry M. Anderson<br>Calgary, Alberta, Canada                | Senior Vice President and Chief Operating Officer | Senior Vice President and Chief Operating Officer of ARC Resources           |
| David P. Carey<br>Calgary, Alberta, Canada                   | Senior Vice President, Capital Markets            | Senior Vice President, Capital Markets of ARC Resources                      |
| Terry N. Gill<br>Calgary, Alberta, Canada                    | Senior Vice President, Corporate Services         | Senior Vice President, Corporate Services of ARC Resources                   |
| Kristen J. Bibby<br>Calgary, Alberta, Canada                 | Vice President, Finance                           | Vice President, Finance of ARC Resources                                     |
| Jay B. Billesberger<br>Calgary, Alberta, Canada              | Vice President, Information Technology            | Vice President, Information Technology of ARC Resources                      |
| Sean R. A. Calder<br>Calgary, Alberta, Canada                | Vice President, Production                        | Vice President, Production of ARC Resources                                  |
| Larissa M. Conrad<br>Calgary, Alberta, Canada                | Vice President, Engineering                       | Vice President, Engineering of ARC Resources                                 |
| Neil A. Groeneveld<br>Calgary, Alberta, Canada               | Vice President, Geosciences and Exploration       | Vice President, Geosciences and Exploration of ARC Resources                 |
| Wayne D. Lentz<br>Calgary, Alberta, Canada                   | Vice President, Strategy and Business Development | Vice President, Strategy and Business Development of ARC Resources           |
| Karen A. Nielsen<br>Calgary, Alberta, Canada                 | Vice President, Operations                        | Vice President, Operations of ARC Resources                                  |
| Grant A. Zawalsky <sup>(1)</sup><br>Calgary, Alberta, Canada | Corporate Secretary                               | Managing Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors) |

Note:

- (1) Mr. Zawalsky is not considered to be an "executive officer" of ARC as defined by NI 51-102 as he does not perform a policy-making function in respect of the Corporation.

## Membership of Board Committees

The following chart sets out the membership of the committees of the Board of Directors as at December 31, 2014.

| Name of Director                        | Audit | Reserves | Risk  | Human Resources & Compensation | Policy & Board Governance | Health, Safety & Environment |
|---|-------|----------|-------|--------------------------------|---------------------------|------------------------------|
| <b><i>Non-Independent Directors</i></b> |       |          |       |                                |                           |                              |
| John P. Dielwart                        |       |          | √     |                                |                           | Chair                        |
| <b><i>Independent Directors</i></b>     |       |          |       |                                |                           |                              |
| Mac H. Van Wielingen                    |       |          | √     | √                              | √                         |                              |
| Fred J. Dymont                          | √     | √        | Chair |                                |                           |                              |
| Timothy J. Hearn                        |       |          |       | Chair                          | √                         | √                            |
| James C. Houck                          | √     | Chair    | √     |                                |                           |                              |
| Harold N. Kvisle                        |       |          |       | √                              | √                         |                              |
| Kathleen M. O'Neill                     | Chair |          | √     |                                |                           | √                            |
| Herbert C. Pinder, Jr.                  |       | √        |       | √                              | Chair                     |                              |
| William G. Sembo                        | √     | √        |       |                                |                           |                              |

The Audit, Reserves, Human Resources and Compensation and the Policy and Board Governance committees are entirely comprised of independent directors. The Risk and Health, Safety and Environment committees are comprised of a majority of independent directors.

Mr. Dielwart, who is the Chair of the Health, Safety and Environment Committee and is a member of the Risk Committee, retired from the position of CEO of ARC Resources effective January 1, 2013 but remains as a director and will be considered to be a non-independent director for a period of three years from his retirement. Mr. Stadnyk was promoted to the position of President and CEO of ARC Resources effective January 1, 2013 and was appointed as a director on such date. Mr. Stadnyk will be considered to be a non-independent director.

With the exception of the following individuals, the officers and directors have held the position set forth above (or other positions with the same organization) as their principal occupation for the last five years.

- Prior to January 1, 2013, John P. Dielwart was Chief Executive Officer of ARC Resources and prior to February 2009 was President and Chief Executive Officer of ARC Resources.
- Prior to August 2012, James C. Houck was President and Chief Executive Officer of The Churchill Corporation.
- Prior to September 2012, Harold N. Kvisle was an independent businessman and prior to July 2010 was President and Chief Executive Officer of TransCanada Corporation and TransCanada Pipelines Ltd.
- Prior to August 2013, Karen Nielsen was Vice President, Engineering of Birchcliff Energy Ltd. and prior to October 2009 was Vice President, Operations of Birchcliff Energy Ltd.
- Prior to February 2014, Larissa Conrad was Manager, Engineering South at ARC Resources and prior to August 2011 was Team Lead, Government & Regulatory Relations at EnCana Corporation.
- Prior to August 2014, Kristen Bibby was VP Finance and Chief Financial Officer at Verano Energy Limited and prior to January 2011 was VP Finance and Chief Financial Officer of Petrolifera Petroleum Limited.

## **Officer Biographies**

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

### ***Myron M. Stadnyk, P.Eng.***

Mr. Stadnyk is President and Chief Executive Officer of ARC Resources and has overall management responsibility for the Company. Mr. Stadnyk joined ARC in 1997, as the Company's first operations employee, and in 2005 was appointed Senior Vice President, Operations and Chief Operating Officer. From 2009 to 2012, he held the position of President and Chief Operating Officer. Prior to joining ARC, 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 joined ARC's Board of Directors in 2013. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and currently serves as a governor for the Canadian Association of Petroleum Producers. Mr. Stadnyk is also a member of the board of directors for STARS (Shock Trauma Air Rescue Society) Ambulance.

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

Mr. Dafoe is Senior Vice President and Chief Financial Officer of ARC Resources and oversees the finance, treasury, accounting, tax and marketing teams at ARC. Prior to being appointed to the role of Senior Vice President and Chief Financial Officer in 2014, Mr. Dafoe held the position as Senior Vice President, Finance. Mr. Dafoe joined ARC in 1999 as the Controller, after 13 years with various companies in the finance and accounting area of the oil and gas industry. He has a Bachelor of Commerce (Honours) degree from the University of Manitoba and obtained his Certified Management Accountant's designation in 1995.

### ***Terry M. Anderson, P. Eng.***

Mr. Anderson is Senior Vice President and Chief Operating Officer of ARC Resources with responsibility for the execution of all aspects of ARC's operations and capital program. He has over 20 years of operations and engineering experience. 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 Engineers and Geoscientists of Alberta, Saskatchewan and British Columbia.

### ***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, communications and corporate governance. Mr. Carey brings over 30 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 and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

### ***Terry N. Gill, B.PE.***

Mr. Gill is Senior Vice President, Corporate Services of ARC Resources and oversees all human resources, information technology and legal 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 has spent over 15 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.

### ***Kristen (Kris) J. Bibby, B.Comm, CA***

Mr. Bibby is Vice President, Finance of ARC Resources and is responsible for ARC's financial risk and research, tax and treasury related activities. He has over 17 years of experience in finance and accounting roles within the oil and gas industry. Prior to joining ARC in 2014, Mr. Bibby held the position as Chief Financial Officer at a junior oil and gas company with international operations. He has a Bachelor of Commerce degree from the University of Saskatchewan, and is a member of the Canadian and Alberta Institute of Chartered Accountants.

**Jay B. 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 15 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.

**Sean R. A. Calder, P.L.Eng.**

Mr. Calder is Vice President, Production of ARC Resources, and manages all aspects of field production operations and health, safety and environment. He has over 18 years of broad industry experience including field operations, drilling and completions and facility management. Mr. Calder joined ARC in 2005, and since this time has taken on roles of increasing responsibility. Prior to joining ARC, he worked at a major oil and gas company. Mr. Calder has a Bachelor of Applied Petroleum Engineering Technology degree from the Southern Alberta Institute of Technology (SAIT). He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA), as well as the Association of Science and Engineering Technology Professionals in Alberta (ASET).

**Larissa (Lara) M. Conrad, P.Eng.**

Ms. Conrad is Vice President, Engineering with responsibility for all engineering and joint venture activities. She has over 15 years of experience in reservoir, exploration, development and production engineering. Ms. Conrad joined ARC in 2011, and since this time has taken on roles of increasing responsibility. Prior to joining ARC, Ms. Conrad spent 14 years with a major Canadian oil and gas producer. Ms. Conrad has a Bachelor of Science degree in Mechanical Engineering from the University of Waterloo and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

**Neil A. Groeneveld, P. Geol.**

Mr. Groeneveld is Vice President, Geosciences and Exploration of ARC Resources and is responsible for the execution of geophysical and geological activities. He has over 20 years of experience in the western Canadian oil and gas business 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 degree in Geology from the University of Regina and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

**Wayne D. Lentz, P.Eng.**

Mr. Lentz is Vice President, Strategy and Business Development of ARC Resources and is responsible for strategic planning and related activities. He brings over 25 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 oil and gas 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 and Geoscientists of Alberta (APEGA).

**Karen A. Nielsen, P.Eng.**

Ms. Nielsen is Vice President, Operations of ARC Resources and is responsible for overseeing the execution of all aspects of ARC's capital program. She has 25 years of experience in the oil and gas industry with expertise in exploitation, drilling, completions and production operations in western Canada. Prior to joining ARC in 2013, Ms. Nielsen held the position as Vice President, Engineering at a mid-sized Canadian oil and gas company. She has a Bachelor of Science degree (Distinction) in Electrical Engineering from the University of Saskatchewan. Ms. Nielsen is a member of the Association of Professional Engineers and Geoscientist of Alberta (APEGA) and British Columbia (APEGBC).

**Grant A. Zawalsky, B.Comm, LL.B**

Mr. Zawalsky acts as Corporate Secretary for ARC Resources. He is a managing partner at the law firm of Burnet, Duckworth & Palmer LLP, and has over 30 years of experience in securities and corporate law including securities offerings, mergers and acquisitions, and corporate governance. Mr. Zawalsky has a Bachelor of Commerce degree and an LL.B. from the University of Alberta. He has extensive Corporate Secretary experience at small to mid-cap companies in the energy industry. Mr. Zawalsky is currently a director of a number of public and private energy companies including, Nuvista Energy Ltd., PrairieSky Royalty Ltd., Whitecap Resources Inc. and Zargon Oil & Gas Ltd.

All of the current directors of ARC Resources were elected as directors of ARC Resources Ltd. on May 14, 2014 to hold office until the next annual meeting of ARC Resources, which is scheduled to be held on April 30, 2015. As at December 31, 2014, the directors and officers of ARC Resources, as a group, beneficially owned, or controlled or directed, directly or indirectly, 2,452,274 Common Shares or approximately 0.8 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, 2014, the members of the Audit Committee were Kathleen O'Neill (Chair), Fred J. Dymont, James C. Houck and William G. Sembo; each is independent and financially literate within the meaning of MI 52-110. Effective February 11, 2015, following the 2014 year-end Board meeting, Fred Dymont resigned from the audit committee. The following comprises a brief summary of each member's education and experience:

#### ***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 the Bank of Montreal (BMO) Financial Group with accountability for a number of major business units. Prior to joining BMO Financial Group in 1994, she was a partner with PricewaterhouseCoopers. Ms. O'Neill is an FCPA, FCA (Fellow of Institute of Chartered Accountants) and has an ICD.D designation from the Institute of Corporate Directors. Ms. O'Neill was a member of the Steering Committee on Enhancing Audit Quality sponsored by the Canadian Institute of Chartered Accountants and the Canadian Public Accountability Board. In 2014, Ms. O'Neill was awarded Canada's Most Powerful Women: Top 100 Award by the Women's Executive Network. Ms. O'Neill currently serves as the Chair of the audit committee for Invesco Canada Funds, Cadillac Fairview Corporation Ltd. and Finning International Inc., the world's largest Caterpillar dealer. Ms. O'Neill is the past Chair of St Joseph's Health Centre and St Joseph's Health Centre Foundation of Toronto. She has been a director of ARC since 2009.

#### ***Fred J. Dymont***

Mr. Dymont has over 40 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. Dymont received a Chartered Accountant designation from the province of Ontario in 1972. Mr. Dymont is a director on the boards of Tesco Corporation, Transglobe Energy Corporation, Major Drilling Group International, WesternZagros Resources Ltd., and Avalon Oil & Gas Ltd. He has been a director of ARC since 2003.

#### ***James C. Houck***

Mr. Houck has over 35 years of diversified experience in the oil and gas industry. Most recently, he held the position as President and Chief Executive Officer of the Churchill Corporation, a construction and industrial services 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 from Trinity University in San Antonio and a Masters in Business Administration from the University of Houston. Mr. Houck currently serves as a director on the WesternZagros Resources Ltd. board. He has been a director of ARC since 2008.

#### ***William G. Sembo***

Mr. Sembo has over 40 years of industry experience. He retired from his role as Vice Chairman at RBC Capital Markets LLC in 2013. Mr. Sembo has spent the majority of his career in energy investment banking and has expertise in investment banking, corporate credit and mergers and acquisitions. Prior to joining RBC in 1986, Mr. Sembo held Corporate Finance and Financial Planning positions with Toronto Dominion Bank and Asamera Inc., respectively. Mr. Sembo has a Bachelor of Arts in Economics from the University of Calgary. He brings extensive capital markets expertise as well as a broad base of corporate governance experience to ARC, having served as a director for both private and public boards as well as numerous not-for-profit organizations. Mr. Sembo currently serves as a director

for Canadian Utilities Ltd., OMERS Energy Services LP, CEDA International Corporation and Calgary Scientific Inc. He has been a director of ARC since 2013.

### 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 LLP. The following is a summary of the external audit services fees by category.

| Summary of External Audit Service Fees | 2014      | 2013      |
|--|-----------|-----------|
| Audit Fees                             | \$903,578 | \$939,043 |
| Audit Related Fees <sup>(1)</sup>      | \$70,727  | \$0       |
| Tax Fees <sup>(2)</sup>                | \$0       | \$0       |
| All Other Fees <sup>(3)</sup>          | \$17,933  | \$18,003  |

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.
- (3) The assessment fee billed by The Canadian Public Accountability Board per the National Instrument 52-108 *Auditor Oversight* mandate for reporting issuers to have an audit completed by a CPAB participant firm.

### 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 one 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 one 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

The Board of Directors of ARC Resources has established a dividend policy of paying monthly dividends to holders of Common Shares, which will be paid to Shareholders of record on or about the 15th day of each month. The payment of dividends by the Corporation commenced upon the Trust Conversion with a dividend declared to Shareholders of record on January 31, 2011 made payable on February 15, 2011. Prior to the Trust Conversion, ARC paid a regular distribution to holders of Trust Units since its inception in July of 1996.

It is expected that the dividends declared and paid will be "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. However, 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 ARC Resources 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 were made in the last three completed financial years of ARC:

| <b>Dividends</b> | <b>2014</b>   | <b>2013</b>   | <b>2012</b>   |
|------------------|---------------|---------------|---------------|
| January          | \$0.10        | \$0.10        | \$0.10        |
| February         | \$0.10        | \$0.10        | \$0.10        |
| March            | \$0.10        | \$0.10        | \$0.10        |
| April            | \$0.10        | \$0.10        | \$0.10        |
| May              | \$0.10        | \$0.10        | \$0.10        |
| June             | \$0.10        | \$0.10        | \$0.10        |
| July             | \$0.10        | \$0.10        | \$0.10        |
| August           | \$0.10        | \$0.10        | \$0.10        |
| September        | \$0.10        | \$0.10        | \$0.10        |
| October          | \$0.10        | \$0.10        | \$0.10        |
| November         | \$0.10        | \$0.10        | \$0.10        |
| December         | \$0.10        | \$0.10        | \$0.10        |
| <b>Total</b>     | <b>\$1.20</b> | <b>\$1.20</b> | <b>\$1.20</b> |

## MARKET FOR SECURITIES

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 on the TSX for the periods indicated (as quoted by Bloomberg):

| Toronto Stock Exchange<br>2014 Period | High<br>\$ | Low<br>\$ | Volume     |
|---------------------------------------|------------|-----------|------------|
| January                               | 29.41      | 27.97     | 16,857,218 |
| February                              | 30.40      | 28.49     | 18,218,181 |
| March                                 | 30.45      | 29.04     | 15,675,244 |
| April                                 | 33.29      | 30.45     | 14,749,467 |
| May                                   | 32.17      | 30.89     | 12,527,157 |
| June                                  | 33.31      | 31.87     | 13,740,822 |
| July                                  | 32.40      | 30.04     | 13,368,697 |
| August                                | 31.66      | 29.30     | 14,546,776 |
| September                             | 31.08      | 28.80     | 20,655,055 |
| October                               | 29.09      | 26.06     | 23,675,439 |
| November                              | 29.36      | 25.60     | 17,283,556 |
| December                              | 27.61      | 23.43     | 30,550,016 |

## INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, 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. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB is currently undergoing a consultation process to update the current regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act*, which received Royal Assent on June 29, 2012 (the "**Prosperity Act**"). In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

#### Natural Gas

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

Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m<sup>3</sup> per day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

### **The North American Free Trade Agreement**

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico 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. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

### **Royalties and Incentives**

#### ***General***

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

Occasionally the governments of the western Canadian provinces create incentive programs, often during periods of low commodity prices. Such programs can provide royalty rate reductions, royalty holidays or royalty tax credits to encourage exploration and development activity.

The following is a summary description of key royalty programs in the jurisdictions in which we operate that affect our capital investment decisions.

#### ***Alberta***

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

Royalties are currently paid pursuant to "*The New Royalty Framework*" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "*Alberta Royalty Framework*", which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40 per cent.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36 per cent.

Royalties rates for natural gas liquids are 30 per cent for propane and butane and 40 per cent for pentanes (plus).

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act (Alberta)*. The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, the tax levied is four per cent of revenues reported from fee simple mineral title properties.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the *"Emerging Resource and Technologies Initiative"*). Specifically, some of the incentive programs that apply to our key properties include:

- Horizontal oil wells will receive a maximum royalty rate of five per cent with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal gas wells will receive a maximum royalty rate of five per cent for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010.

### **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. 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. Royalties on natural gas liquids are levied at a flat rate of 20 per cent of the sales volume.

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

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs. A program that applies to our key properties is the following:

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

intended to reflect the higher drilling and completion costs. Effective April 1, 2014, the Deep Well Royalty Credit Program was extended to include a second tier which applies to horizontal wells with a true vertical depth of less than 1,900 meters if spud after March 31, 2014.

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

### **Saskatchewan**

In Saskatchewan, the amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Natural gas liquids and by-products recovered at gas processing plants are not subject to a royalty. Gas liquids which are produced and measured at the wellhead are treated as crude oil for royalty purposes.

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

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs. Programs that apply to our key properties include the following:

- *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<sup>3</sup> for non-deep horizontal oil wells and 16,000 m<sup>3</sup> for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;
- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of one per cent of gross revenues on EOR projects pre-payout and 20 per cent of EOR operating income post-payout and a freehold production tax of zero per cent pre-payout and eight per cent post-payout on operating income from EOR projects; and
- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

### **Manitoba**

In Manitoba, the royalty amount payable on oil produced from Crown lands depends on the classification of the oil which is dependent on the date of drill, re-entry, enhanced recovery project implementation date, or various other key dates. 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 per cent 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. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2 per cent of the volume sold, calculated for each production month. There is no freehold production tax payable on gas consumed as lease fuel.

The Government of Manitoba maintains a Drilling Incentive Program (the "Program") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a holiday oil volume ("HOV") 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 10 years of the finished drilling date or the completion date of a major workover.

The Program includes the following components which apply to our key properties, such components being subject to additional considerations under the Crown Royalty and Incentives Regulation:

- *Horizontal Well Incentive* provides an "HOV" of 8,000 m<sup>3</sup> for any horizontal well drilled after December 31, 2014 and prior to January 1, 2019 achieving an angle of at least 80 degrees for a minimum distance of 100 metres; and
- *Pressure Maintenance Project Incentive* provides a one-year exemption from the payment of Crown royalties or freehold production taxes for a unit tract in which an injection well is drilled or a well is converted to water injection. For a well that is converted to injection after December 31, 2014 and before January 21, 2019 and that has a remaining HOV, the exemption will be extended to 18 months.

## **Land Tenure**

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

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia expanded its policy of deep rights reversion for new leases to provide for the reversion of all formations that do not contain an identified oil or natural gas pool at the end of their primary term ("zone specific retention").

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 licences. For leases and licences issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease and intermediate term of the license.

## **Environmental Regulation**

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

Pursuant to the Prosperity Act, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. The changes to the

environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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

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

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 km<sup>2</sup> in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 per cent of the province's oilsands resources and much of the Cold Lake oilsands area.

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

The next regional plan to take effect is the South Saskatchewan Regional Plan ("**SSRP**") which covers approximately 83,764 km<sup>2</sup> and includes 45 per cent of the provincial population. The SSRP was approved by the Cabinet of the provincial government on July 23, 2014 and came into effect force on September 1, 2014.

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

In British Columbia, the Oil and Gas Activities Act (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers, and other operators of oil and gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**Commission**") has broad powers, particularly with respect to compliance and enforcement and

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

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

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

### **Liability Management Rating Programs**

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

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

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

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

On July 4, 2014, the AER introduced the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells ("Directive 013")*. The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee will be required to bring 20 per cent of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*.

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

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

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

## **Climate Change Regulation**

### ***Federal***

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

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

## **Alberta**

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

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

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

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of \$15 per tonne of CO<sub>2</sub> equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

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

## **British Columbia**

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is \$30 per tonne of CO<sub>2</sub> equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

In the 2012 Budget, British Columbia announced that the government will undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review in 2013, British Columbia confirmed that it will keep its revenue-neutral carbon tax, the current carbon tax rates and tax base will be maintained and revenues will continue to be returned through tax reductions.

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

### **Saskatchewan**

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20 per cent reduction in GHG emissions from 2006 levels by 2020. The MRGGA and related regulations have not yet been proclaimed in force.

### **Manitoba**

The Government of Manitoba commenced public consultations with respect to the development of a cap and trade system to reduce GHG emissions in 2010. The enactment of *The Climate Change and Emissions Reductions Act* (Manitoba) set emission reduction targets as of December 31, 2012 at six per cent below 1990 emissions and details the commitment of the Government of Manitoba to various initiatives in an effort to reduce GHG emissions. However, no legislation has been enacted which imposes mandatory emission reduction targets on emitters.

## **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".

### **Risks Relating to Our Business and Operations**

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

Our operational and financial results are dependent on the prices received for oil and natural gas production. Oil and natural gas prices respond to supply/demand imbalances and are volatile.

Oil and natural gas prices are determined by supply and demand and in the case of oil prices, political factors and a variety of additional factors beyond our control. These factors include but are not limited to economic conditions, both in North America and worldwide, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability, the increased capacity to bring new production on stream due to technology such as multi-stage fracturing, the foreign supply of oil and natural gas, supply disruption, transportation disruption, the price of foreign imports and the availability of alternative fuel sources. North America has an abundance of natural gas reserves, primarily as a result of advancements in hydraulic fracturing techniques. Natural gas prices are impacted by North American inventory levels which have increased year-over-year due to production growth in North America.

Any substantial and extended decline in the price of oil and natural gas could have an adverse effect on the carrying value of our proved and probable reserves, net asset value, borrowing capacity, production, revenues, profitability and funds from operations, 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***

We deliver our products through gathering, processing and pipeline systems (some of which we do not own), by truck, and by rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability,

proximity and capacity of these gathering, processing and pipeline systems, and truck and rail. This access to market affects the regional price differentials. This differential could result in the inability to realize the full economic potential of our crude oil production. Although the transportation of crude oil by pipeline, rail car and by barge is expanding, the lack of firm transportation capacity continues to affect the oil industry and the potential to limit the ability to produce and to market oil production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil. Even though there are currently no restrictions on the flow of natural gas in North America, future pipeline restrictions may occur. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, results of operations and funds from operations.

ARC has entered into certain long-term take-or-pay transportation commitments to deliver products through third-party owned infrastructure which creates a financial liability and there can be no assurance that future volume commitments will be met which may adversely affect our income and funds from operations. For more information regarding these long-term transportation commitments, see Note 19 "Commitments and Contingencies" in ARC's Audited Consolidated Financial Statements as at and for the year ended December 31, 2014 which section is incorporated in this Annual Information Form by reference and is found on our SEDAR profile at [www.sedar.com](http://www.sedar.com).

Producers have increasingly turned to rail as an alternative means of oil transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Following major accidents in Lac-Mégantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

Primarily due to aging infrastructure, certain pipeline leaks have gained media, environmental and other stakeholder attention. This may result in additional regulation or changes in law which could impede the conduct of our business or make our operations more expensive.

A portion of our production is processed through facilities owned by third parties which we do 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 adversely affect our ability to process our production and to deliver the same for sale.

***Fluctuation in the value of the Canadian dollar relative to the U.S. dollar may adversely affect our financial condition***

Fluctuations in foreign exchange rates of the Canadian dollar relative to the U.S. dollar may affect ARC's revenue as global oil prices and natural gas liquids, and Canadian natural gas exports to the U.S. are denominated in U.S. dollars. A decrease in the value of the U.S. dollar relative to the Canadian dollar may reduce the price received by ARC for its products in Canadian dollar terms. In addition, ARC holds a significant portion of its debt denominated in U.S. dollars. Since ARC reports in Canadian dollars, U.S. dollar debt is translated to a Canadian dollar equivalent and therefore its reported level of indebtedness is affected by the foreign exchange rate between the U.S. dollar and Canadian dollar. An increase in the U.S. dollar relative to the Canadian dollar will increase the reported value of debt and interest payments, as expressed in Canadian dollars.

***Global economic 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, may cause significant volatility to commodity prices and a decline in funds from operations. Global economic events and conditions may cause a loss of confidence in the broader global credit and financial markets and create a climate of greater volatility, less liquidity, wider credit spreads, a lack of price transparency and increased credit losses. Market events in the future may affect our 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***

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 our dividend policy. The dividend policy is also subject to change in the sole discretion of our Board of Directors. 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 as producing properties decline over time***

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. The production from individual wells and properties declines over time. We currently distribute a portion of our funds from operations, 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 may be dependent on the level of our funds from operations and external sources of capital. 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 may result in a reduction in the value of Common Shares and in a reduction in funds from operations available for the payment of dividends to Shareholders.

***Our hedging activities may negatively impact our income***

We actively manage the risk associated with changes in commodity prices by entering into oil and 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 relative to funds from operations. For more information in relation to our commodity hedging program, see "*Statement of Reserve Data and Other Oil and Gas Information – Forward Contracts*". We also may initiate certain hedges to attempt to mitigate the risk of the Canadian dollar fluctuating in relation to the U.S. dollar. These hedging activities could expose us to losses, which may be material, and to credit risk associated with counterparties with whom we contract.

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

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including land tenure, exploration, development, production, refining, transportation and marketing). 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. In order to conduct oil and gas operations, we require licences from various governmental authorities. There can be no assurance that we will be able to obtain all of the licences and permits that may be required to conduct operations that we may wish to undertake. See "*Industry Conditions*".

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

The loss of our 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 and staff 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.

***Our bank credit facility is subject to renewal, compliance and covenants***

We have a Cdn\$1 billion syndicated credit facility with twelve banks which was drawn by \$84 million as at December 31, 2014. The current maturity date of the facility is November 6, 2018. The terms of the credit facility allow for annual renewals at the request of ARC and at the discretion of the lenders. At December 31, 2014, ARC had US\$809.7 million and Cdn\$51.6 million of long-term debt outstanding in the form of Long-Term Notes ("**Notes**"). The Notes are repayable over the next 12 years. We intend to fund these repayments with existing credit facilities and/or with proceeds from additional note issuances.

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, that additional funds will be able to be obtained or that we will be able to extend or renew our credit facilities.

We are required to comply with covenants under the credit facility and under our 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 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. For more information, see "*Other Information Relating to Our Business – Borrowing*".

***If external sources of capital, borrowings and equity are unavailable, our financial condition could be adversely affected***

We anticipate making substantial capital expenditures for the development of oil and natural gas reserves in the future. Other capital expenditures may also include exploration, undeveloped land and acquisitions from time-to-time. Future capital expenditures will be financed out of funds from operations, borrowings, property dispositions and possible future equity issuances; however, 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 capital expenditure programs.

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. 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, purchasers 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.

Income tax laws, other laws or government incentive programs relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders. 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 (see "Statement of Reserves Data and Other Oil and Gas Information – Forecast Prices and Costs). 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. Current interest rates are low compared to historical levels. An increase in interest rates may 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. Further, the value of our Common Shares may decline in an environment of increasing interest rates as investors' rate of return expectations may be higher.

***Hydraulic fracturing is subject to certain risks***

Hydraulic fracturing can be performed utilizing a number of methods but typically involves the injection of fluids, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. The use of hydraulic fracturing enables the production of 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 hydraulic fracturing 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 our 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 we are ultimately able to produce from our 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, uncontrollable flow of hydrocarbons, 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.

***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 our 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 funds from operations and the payment of dividends to Shareholders.

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. Climate change policy is evolving at regional, national and international levels and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and as a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17 per cent reduction in "**GHG**" emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Although it is not the case today, some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. 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.

Provincial regulation requires the reclamation and abandonment of wells at the end of their production life. 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 and undeveloped land. As a result of such competition, it may be more difficult for us to acquire reserves on beneficial terms. A number 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 program. The inability to hire and retain skilled personnel could adversely impact certain of our operational and financial results.

***Volatility in reported earnings resulting from non-cash charges could adversely affect the market price of our Common Shares and ability to borrow funds***

Our accounting policies conform to International Financial Reporting Standards ("IFRS") which constitutes generally accepted accounting principles in Canada. Accounting under IFRS may result in non-cash charges and/or write-downs of net assets in the financial statements on a quarterly basis. Similarly, non-cash gains and recoveries of asset write-downs may also be recorded from time to time. Income statement volatility resulting from such non-cash gains and losses under IFRS may be viewed unfavourably by the market and could result in an inability to borrow funds and/or could result in a decline in the price of the Common Shares.

For more information as to ARC's current accounting policies and future accounting policy changes, see Note 3 "Summary of Accounting Policies" and Note 4 "Changes in Accounting Policies" in ARC's Audited Consolidated Financial Statements as at and for the year ended December 31, 2014 which section is incorporated in this Annual Information Form by reference and is found on our SEDAR profile at [www.sedar.com](http://www.sedar.com).

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

Our properties are held in the form of licences and leases and working interests in licences and leases. If we or the holder of the 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 we control that, if successful or made into law, could impair our activities on them and result in a reduction of the revenue received by us.

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.

***Liability management programs***

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

***Our information technology systems are subject to certain risks***

We utilize a number of information technology systems for the administration and management of our business. If our ability to access and use these systems is interrupted and cannot be quickly and easily restored then such event could have a material adverse effect on us. Furthermore, although our information technology systems are considered to be secure, if an unauthorized third party is able to access the systems then such unauthorized access may compromise our business in a materially adverse manner.

***Our ability to carry on our business is dependent upon access to our offices and properties***

Our ability to carry on our business is dependent upon the ability of our employees to physically access our offices and properties. If access to our office and properties is interrupted then our ability to administer and manage our business may be materially and adversely affected.

***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. All 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***

Cash dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25 per cent 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 per cent.

***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, September 26, 2011, October 10, 2013 and November 6, 2014 providing for an extendible revolving credit facility up to Cdn\$1 billion. The maturity date of the facility was extended to November 6, 2018 under the existing terms on November 6, 2014.
2. Uncommitted Master Shelf Agreement dated as of November 16, 2000 between ARC Resources and various purchasers, as amended and restated on December 15, 2005 and as amended and restated on September 25, 2014 providing for the issuance and sale of up to an aggregate principal amount of US\$350 million in notes of which US\$28.1 million 5.42% Series C Notes due December 15, 2017, US\$50 million 4.98% Series D Notes due March 5, 2019 and US\$150 million 3.72% Series E Notes due September 25, 2026 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\$0 and US\$9.6 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 of which US\$27.0 million, US\$35 million and Cdn\$11.6 million, respectively, are currently outstanding.
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, of which US\$150 million is currently outstanding.
6. Note Purchase Agreement dated as of August 23, 2012 between ARC Resources and various purchasers with respect to US\$60.0 million 3.31% Series G Notes due August 23, 2021, US\$300 million 3.81% Series H Notes due August 23, 2024 and Cdn\$40.0 million 4.49% Series I Notes due August 23, 2024, of which US\$60 million, US\$300 million and Cdn\$40 million, respectively, is currently outstanding.

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 our SEDAR profile at [www.sedar.com](http://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 LLP, our auditors. As at the date hereof the designated professionals of GLJ, as a group, beneficially owned, directly or indirectly, less than one per cent of our outstanding securities, including the securities of our associates and affiliates. Deloitte 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. Grant A. Zawalsky, 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, will be contained in the Information Circular - Proxy Statement of the Corporation which relates to the Annual Meeting of Shareholders to be held on April 30, 2015. Additional financial information is provided in our consolidated financial statements and accompanying management's discussion and analysis for the year ended December 31, 2014, which have been filed on our SEDAR profile at [www.sedar.com](http://www.sedar.com). Other additional information relating to us may be found on our SEDAR profile at [www.sedar.com](http://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, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2014, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

| <u>Independent<br/>Qualified<br/>Reserves<br/>Evaluator</u> | <u>Description and<br/>Preparation Date<br/>of Evaluation<br/>Report</u> | <u>Location of<br/>Reserves<br/>(Country or<br/>Foreign<br/>Geographic<br/>Area)</u> | <u>Net Present Value of Future Net Revenue<br/>(before income taxes, 10% discount rate - MM \$)</u> |                  |                 |              |
|---|--|--|---|------------------|-----------------|--------------|
|   |  |  | <u>Audited</u>  | <u>Evaluated</u> | <u>Reviewed</u> | <u>Total</u> |
| GLJ Petroleum<br>Consultants Ltd.                           | Corporate<br>Summary<br>January 12, 2015                                 | Canada   | -   | 5,907            | -               | 5,907        |

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the 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 11, 2015

(signed) "Bryan M. Joa"  
Bryan M. Joa, 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, 2014 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) "*Myron Stadnyk*"  
Myron Stadnyk  
President and Chief Executive Officer

(signed) "*Terry Anderson*"  
Terry Anderson  
Senior Vice President and Chief Operating Officer

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

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

March 11, 2015

## APPENDIX C

### MANDATE OF THE AUDIT COMMITTEE (FEBRUARY 11, 2015)

#### 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 review management's implementation and maintenance of an effective system of internal control over financial reporting and disclosure control over financial reporting.
- To increase the credibility and objectivity of financial reports.
- To facilitate in-depth discussions between directors on the Committee, management and external auditors.

The primary responsibility for the financial reporting, information systems, risk management and internal and disclosure controls of the Corporation is vested in management and overseen by the Board of Directors of the Corporation. At each meeting, the Committee may meet separately with management and will meet in separate, closed sessions with the external auditors and then with the independent directors in attendance.

#### Mandate and Responsibilities of Committee

##### *Financial Reporting and Related Public Disclosure*

1. It is a primary responsibility of the Committee to review and recommend for approval to the Board of Directors the annual and quarterly financial statements of the Corporation. The Committee is also to review and recommend to the Board of Directors for approval the financial statements and related information included in prospectuses, management discussion and analysis (MD&A), financial press releases, information circular-proxy statements and annual information forms (AIF). The process should include but not be limited to:
  - a. reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
  - b. reviewing significant management judgments and estimates that may be material to financial reporting including alternative treatments and their impacts;
  - c. reviewing the presentation and impact of any significant risks and uncertainties that may be material to financial reporting including alternative treatments and their impacts;
  - d. reviewing accounting treatment of significant, unusual or non-recurring transactions;
  - e. reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
  - f. reviewing unresolved differences between management and the external auditors;
  - g. determining through inquiry if there are any related party transactions and ensure the nature and extent of such transactions are properly disclosed; and

- h. reviewing all financial reporting relating to risk exposure including the identification, monitoring and mitigation of business risk and its disclosure.
2. The Committee shall 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.

***Internal Controls Over Financial Reporting and Information Systems***

3. It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to the Corporation's internal control over financial reporting and information systems. The process should include but not be limited to:
- a. inquiring as to the adequacy and effectiveness of the Corporation's system of internal controls over financial reporting and review the evaluation of internal controls over financial reporting by external auditors;
  - b. establishing procedures for the confidential, anonymous submission by employees of the Corporation of concerns relating to accounting, internal control over financial reporting, auditing or Code of Business Conduct and Ethics matters and periodically review a summary of complaints and their related resolution; and
  - c. establishing procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters.

***Extractive Sector Transparency Measures Act***

4. It is the responsibility of the Committee to satisfy itself on behalf of the Board to review management's process for certification under the *Extractive Sector Transparency Measures Act* (Canada).

***External Auditors***

5. With respect to the appointment of external auditors by the Board, the Committee shall:
- a. 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;
  - b. review the terms of engagement of the external auditors, including the appropriateness and reasonableness of the auditors' fees;
  - c. recommend to the Board appointment of external auditors and the compensation of the external auditors;
  - d. when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;
  - e. 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;
  - f. inquire as to the independence of the external auditors and obtain, at least annually, a formal written statement delineating all relationships between the external auditors and the Corporation as contemplated by Independence Standards Board No. 1; and
  - g. discuss with the external auditors, without management being present, the quality of the Corporation's financial and accounting personnel, the completeness and accuracy of the Corporation's financial statements and elicit comments of senior management regarding the responsiveness of the external auditors to the Corporation's needs.
6. The Committee shall review with the external auditors (and the internal auditor if one is appointed by the Corporation) their assessment of the internal control over financial reporting of the Corporation, their written reports containing recommendations for improvement of internal control over financial reporting and other suggestions as appropriate, and management's response and follow-up to any identified weaknesses.
7. The Committee shall also review and approve 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.

**Compliance**

8. It is the responsibility of the Committee to review management's process for the certification of annual and interim financial reports in accordance with required securities legislation.
9. It is the responsibility of the Committee to ascertain compliance with covenants under loan agreements.
10. The Committee shall review the Corporation's compliance with all legal and regulatory requirements as it pertains to financial reporting, taxation, internal control over financial reporting and any other area the Committee considers to be appropriate relative to its mandate or as may be requested by the Board of Directors.

**Other Matters**

11. It is the responsibility of the Committee to 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.
12. The Committee may also review any other matters that the Audit Committee feels are important to its mandate or that the Board chooses to delegate to it.
13. The Committee shall undertake annually a review of this mandate and make recommendations to the Policy and Board Governance Committee as to proposed changes.

**Composition**

14. 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 Section 1.4 and 1.5 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, be reasonably expected to interfere with the exercise of the member's independent judgment.
15. The Chair of the Committee is appointed by the Board of Directors.
16. A quorum shall be a majority of the members of the Committee.
17. 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**

18. The Committee shall meet at least four times per year and/or as deemed appropriate by the Committee Chair.
19. The Committee shall meet not less than quarterly with the auditors, independent of the presence of management.
20. 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.
21. 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.
22. The Controller and such other staff as appropriate to provide information to the Committee shall attend meetings upon invitation by the Committee.

**Reporting / Authority**

23. 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).
24. Supporting schedules and information reviewed by the Committee shall be available for examination by any director.
25. 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.
26. 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.