ARC Resources Ltd.

2017 Annual Information Form

March 15, 2018

ARC RESOURCES LTD

TSX: ARX

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GLOSSARY OF TERMS

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

ARC, **We**, **Us**, **Our, Corporation** means ARC Resources and all its controlled entities as a consolidated body at the applicable time and, prior to the completion of the Trust Conversion, the Trust and all its controlled entities as a consolidated body at the applicable time;

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 maintained by the Society of Petroleum Evaluation Engineers (Calgary chapter) as amended from time to time;

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

DRIP means our dividend reinvestment plan;

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

GLJ Report means the report prepared by GLJ and dated February 8, 2018 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to ARC's properties at December 31, 2017 and evaluating the light oil, shale gas and natural gas liquids resources located in the NE BC Montney;

NE BC Montney means our lands in northeast British Columbia comprised of the Dawson, Parkland, Tower, Sunrise, Sunset, Sundown, Septimus, Attachie, Red Creek 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;

SDP means our stock dividend program;

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 of 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," "target," "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; as to the development of our proved undeveloped reserves and probable undeveloped reserves; as to our future development activities, the status of our enhanced recovery projects, forward contracts and transportation commitments, reclamation and abandonment obligation, tax horizon, exploration and development activities and production estimates; and in Appendix C entitled "Contingent Resource Estimates" as to our 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 these 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 to estimates 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 crude oil and natural gas properties; crude oil and natural gas production levels; the size of the crude oil and natural gas reserves and of our 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 crude 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, policy and control and changes in governmental legislation; changes in income tax laws, royalty rates and other incentive programs; uncertainties associated with estimating crude oil and natural gas reserves and resources; risks associated with acquiring, developing and exploring for crude 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 crude 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 and skilled personnel, acquisitions of reserves and undeveloped lands; 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 (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at 1200, 308 - 4th Avenue SW, Calgary, Alberta, T2P 0H7.

ABBREVIATIONS AND CONVERSIONS

Oil and NGLs	
bbl	barrel
Mbbl	thousand barrels
MMbbl	million barrels
bbl/d	barrels per day
NGLs	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 American Petroleum Institute (API) gravity scale
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
GJ	gigajoules
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
$MM	million dollars

We have adopted the standard of 6 Mcf:1 barrel when converting natural gas to boe. Boe may be misleading, particularly if used in isolation. **A boe conversion ratio of six 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.**

This Annual Information Form uses the metric "reserve replacement". "Reserve replacement" is calculated by dividing the annual 2P reserve additions (in boe) by ARC's annual production (in boe). Management uses this measure to determine the relative change of its reserves based on a period of time. Such metric does not have a standardized meaning and may not be comparable to similar measures presented by other companies. As such, it should not be used to make comparisons. Management uses oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare ARC's performance over time, however, such measures are not reliable indicators of ARC's future performance and future performance may not compare to the performance in previous periods.

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
barrels	cubic metres	0.159
cubic metres	barrels	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 2017 of 122,937 boe per day. ARC's business activities include the exploration, development and production of crude oil, natural gas and natural gas liquids in four core areas located in Alberta and British Columbia, 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 TSX under the symbol ARX and currently pays a monthly dividend to its Shareholders.

At December 31, 2017, ARC had 471 professional, technical and support staff, with 254 employees in the Calgary office and 217 employees located across ARC's operating areas.

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

ORGANIZATIONAL STRUCTURE

ARC Resources is a sole legal entity and does not have any material subsidiaries or affiliates as of December 31, 2017.

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; this commitment is supported by its 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:

High-quality, long-life assets – ARC's suite of assets includes primarily Montney and Cardium assets. ARC's Montney assets consist of world-class resource play properties, concentrated in northeast British Columbia and northern Alberta. The Montney assets provide substantial growth opportunities, which ARC will pursue to create value through long-term profitable development. Other assets are located in Alberta and include core assets in the Cardium formation in the Pembina area of Alberta. These assets deliver stable production and contribute cash to fund future development and support ARC's dividend.

Health, safety and environmental and operational excellence – In the current competitive environment, achieving top-tier capital efficiency and low cost operations while operating in a safe and environmentally responsible manner are critical to realizing profitability. ARC is committed, where it makes sense, to own and operate its own infrastructure and is deliberate in securing takeaway for its products at optimal pricing.

Financial flexibility – ARC provides returns to Shareholders through a combination of a monthly dividend, currently $0.05 per share per month, and the potential for capital appreciation. ARC's long-term goal is to fund dividend payments and capital expenditures necessary for the replacement of production declines using funds from operations(1). ARC will finance profitable growth activities through a combination of sources including funds from operations, proceeds from property dispositions, debt capacity, and when appropriate, equity issuance. ARC chooses to maintain prudent debt levels, targeting its net debt to be between one to 1.5 times annualized funds from operations and less than 20 per cent of total capitalization over the long term(1). ARC maintains a risk management program to reduce the volatility of sales revenues and increase the certainty of funds from operations.

Top talent and strong leadership culture – ARC is committed to the attraction, retention and development of top talent 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.

(1) Refer to Note 16 "Capital Management" in the financial statements and to the sections entitled "Funds from Operations" and "Capitalization, Financial Resources and Liquidity" contained within our Management's Discussion and Analysis for the year ended December 31, 2017, which note is incorporated in this Annual Information Form by reference and is found on our SEDAR profile at www.sedar.com.

DEVELOPMENT OF OUR BUSINESS

The following is a description of the general development of our business over the last three financial years. During this period, ARC has operated in one of the most challenging commodity price and capital market environments in the history of our Company.

2015

Annual average production of 114,167 boe per day. ARC achieved full-year production of 114,167 boe per day in 2015. Notably, annual average production was two percent higher than 2014, despite a significantly reduced capital program and the divestment of approximately 4,900 boe per day of production volumes throughout the year, which resulted in an annual volume impact of approximately 3,000 boe per day. New wells brought on in the latter part of the year at Sunrise and Tower to coincide with the completion of new facilities in these areas were the main drivers of increased production volumes.

Proved plus probable reserves of 687 MMboe identified and 190 per cent of produced reserves replaced. GLJ determined ARC's proved plus probable reserves increased two per cent relative to 2014, to total 687 MMboe as at December 31, 2015, and that approximately 190 per cent of produced reserves were replaced through capital development activity.

Capital expenditures totaled $541.6 million. During 2015, ARC invested $541.6 million in capital activities, before land purchases and net acquisitions and dispositions, which included the drilling of 60 gross operated wells (33 crude oil wells, 26 natural gas and liquids-rich natural gas wells and one service well). The majority of capital activity in the year was focused on ARC's profitable northeast British Columbia Montney region.

Commissioning of key infrastructure. Key infrastructure projects were completed during the year, including the commissioning of the Sunrise gas plant in the third quarter of 2015 and the Tower oil battery expansion in the fourth quarter of 2015.

ARC completed $21.1 million of land purchases and "tuck-in" land acquisitions in key development areas. In the Montney region, ARC grew its land position by approximately 210 net sections, increasing its total position to approximately 1,174 net Montney sections, including 641 net sections in northeast British Columbia and an additional 533 net sections in northern Alberta. During 2015, ARC divested of certain non-core assets for gross proceeds of $88.8 million, which included the divestment of its properties in Manitoba in the fourth quarter of 2015.

Equity issuance completed. In January 2015, ARC issued 17.9 million Common Shares at a price of $22.55 per share for aggregate proceeds of $402.7 million on a bought deal basis. Share issuance costs of $16.6 million were incurred as a result of this transaction. The proceeds from the equity issuance were directed to reduce bank indebtedness, increase working capital and fund ARC's ongoing capital programs.

2016

Annual average production of 118,671 boe per day. ARC achieved record full-year production of 118,671 boe per day in 2016, representing a four per cent increase relative to full-year 2015 production. The modest growth in production was achieved despite a reduced capital program and the divestment of approximately 8,800 boe per day of non-core production throughout the year. The increase in production year-over-year was the result of numerous strategic activities, including the commissioning of the expanded oil battery in Tower in late 2015, the commissioning of the Sunrise gas processing facility in mid-2015, and the acquisition of assets in Pembina in 2016.

Proved plus probable reserves of 737 MMboe identified and 260 per cent of produced reserves replaced. GLJ determined ARC's proved plus probable reserves increased seven per cent relative to 2015, to total 737 MMboe as at December 31, 2016, and that approximately 260 per cent of produced reserves were replaced through capital development activity. Acquisition of working interests in Pembina Cardium and disposition of ARC's Saskatchewan and other non-core assets resulted in a net reduction of approximately 21 MMboe proved plus probable reserves.

Capital expenditures totaled $453.4 million. During 2016, ARC invested $453.4 million in capital expenditures, before land and net acquisitions and dispositions. Despite a reduced capital budget, ARC executed a successful capital program in 2016, advancing long-term strategic projects and delivering annual average production that was within guidance. The majority of the capital program was focused on the northeast British Columbia region and included the drilling of 64 gross operated wells (34 crude oil wells, 29 natural gas and liquids-rich natural gas wells and one service well), strategic infrastructure spending on the Dawson Phase III gas processing and liquids-handling facility, and the continued advancement of ARC's large asset base across the Montney play.

Right-sizing of the dividend. In February 2016, ARC's Board of Directors approved a monthly dividend of $0.05 per share, down from the previous level of $0.10 per share, commencing with the February 2016 dividend, payable on March 15, 2016. The lower monthly dividend reduced ARC's funding requirements in the year by approximately $200 million.

Strengthened our base business. In a continued effort to advance our strategy of a concentrated asset base of world-class assets, ARC completed strategic acquisition and divestment activities in 2016. Throughout the year, ARC successfully added to our working interest ownership in the Pembina Cardium, acquiring approximately 3,100 boe per day of light, high netback crude oil production. In December 2016, ARC sold its Saskatchewan assets and operations. The sale included approximately 7,500 boe per day of crude oil and liquids production and 38 MMboe of proved plus probable reserves.

2017

Annual average production of 122,937 boe per day. ARC achieved record full-year production of 122,937 boe per day in 2017, representing a four per cent increase relative to 2016. The increase in production was largely driven by new production from Dawson, where the Phase III gas processing and liquids-handling facility was brought on-stream in mid-June 2017. The increased production at Dawson more than offset the total non-core production that was divested in 2016. Crude oil and liquids production volumes from the Saskatchewan assets that were divested in the fourth quarter of 2016 have been effectively replaced with new production resulting from ARC's 2017 appraisal activities of the liquids-rich Lower Montney horizon.

Proved plus probable reserves of 836 MMboe identified and record 320 per cent of produced reserves replaced. GLJ determined ARC's proved plus probable reserves increased 13 per cent relative to 2016, to total 836 MMboe as at December 31, 2017, and that approximately 320 per cent of produced reserves were replaced through capital development activities, the largest addition of development reserves in corporate history.

Capital expenditures totaled $829.7 million. During 2017, ARC invested $829.7 million in capital expenditures, before land and net acquisitions and dispositions. Capital investment was directed primarily at development activities across ARC's Montney asset base and included significant investment in appraising the long-term development potential of the Lower Montney horizon as well as advancing the liquids-rich Attachie West play towards commercialization. Strategic infrastructure investment was directed at completing construction of Dawson Phase III and initial construction activities for the Sunrise Phase II gas processing facility expansion. ARC drilled 122 wells in 2017 (62 crude oil wells, 59 natural gas and liquids-rich natural gas wells, and one disposal well).

Enhanced strategic optionality within ARC's portfolio of assets. A large focus of ARC's 2017 capital program was the appraisal of the liquids-rich Lower Montney horizon, including the drilling of 21 Lower Montney wells across ARC's acreage. Appraisal activities have resulted in the delineation of a significant portion of ARC's Montney lands, moving inventory into the development stage. Encouraged by recent production results in the liquids-rich Attachie West area, ARC further enhanced the strategic optionality within its portfolio of assets with the purchase of 21 net sections of undeveloped land at Attachie West in the third quarter of 2017 and the drilling of a multi-well demonstration pad in the fourth quarter of 2017.

Commissioning of Dawson Phase III. ARC completed construction of the Dawson Phase III gas processing and liquids-handling facility in June 2017, ahead of schedule and under budget. The facility was designed to process 90 MMcf per day of natural gas and handle up to 7,500 barrels per day of liquids. By year-end, the facility had reached its gas processing capacity. ARC has plans to increase the area's liquids production with the continued development of the liquids-rich Lower Montney horizon.

Physical marketing and financial diversification program. ARC's physical market diversification and financial risk management activities helped to significantly reduce ARC's exposure to ongoing weakness in western Canadian natural gas prices. ARC's natural gas sales portfolio is physically and financially diversified to multiple downstream markets including US Midwest, Henry Hub, and US Pacific Northwest markets. Through ARC's diversification activities, an incremental $0.39 per Mcf was realized in ARC's natural gas price in 2017, while ARC's financial risk management program provided additional cash flow protection with realized cash gains recognized on ARC's natural gas risk management contracts amounting to $0.78 per Mcf. Total realized gains on ARC's risk management contracts in 2017 were $145.0 million, which represented approximately 20 per cent of annual funds from operations.

Elimination of the DRIP and SDP. On February 8, 2017, ARC's Board of Directors approved the elimination of the DRIP and SDP. By canceling these programs, ARC effectively eliminated the dilutive effect of the DRIP and SDP to ARC's existing shareholder base. Beginning with the March 2017 dividend, which was paid on April 17, 2017 to Shareholders of record on March 31, 2017, all Shareholders receive dividend payments in the form of cash.

United States Securities and Exchange Commission deregistration. ARC filed a Form 15F with the Securities Exchange Commission ("SEC") on May 15, 2017 to voluntarily terminate the registration of its securities and its reporting obligations under Section 13(a) and Section 15(d) of the United States Securities Exchange Act of 1934. In determining to deregister, ARC's Board of Directors considered the administrative burden and costs associated with being a US-reporting company and believed that the costs outweighed the benefits.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information is set forth below (the "**Statement**"). The effective date of the Statement is December 31, 2017. 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 8, 2018. The reserves data summarizes our crude oil, natural gas and natural gas liquids reserves and the net present values of future net revenues 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 the abandonment and reclamation of certain wells, pipelines and facilities. 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 ARC's 2017 reserves were in Canada, in the provinces of Alberta and British Columbia. At December 31, 2017 certain assets located in Alberta were classified as assets held for sale and as such were reclassified out of property, plant and equipment and asset retirement obligations on the balance sheet. These assets have booked reserves and were included in the 2017 reserve values and in net present value calculations.

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 and natural gas liquids 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 liquids 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 51-101F2 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.

As per NI 51-101 product type definitions, ARC has provided reserves data for reserves classified as Shale Gas and reserves classified as Tight Oil. ARC's gas reserves and resources in the NE BC and NW AB Montney siltstone are classified as Shale Gas under NI 51-101. ARC's oil reserves and resources in the NE BC and NW AB Montney siltstone are classified as Tight Oil under NI 51-101.

DISCLOSURE OF RESERVES DATA

Company Gross reserves information presented herein is consistent with reserves information disclosed in the February 8, 2018 news release entitled, *"ARC Resources Ltd. Announces Record 320 Per Cent Replacement of Produced Reserves Through Development Activities in 2017".*

Summary of 2017 Oil and Gas Reserves - Based on Forecast Prices and Costs

Company Gross Reserves	Light Crude Oil and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Tight Oil (Mbbl)	Total Oil (Mbbl)	Conventional Natural Gas (Bcf)	Shale Gas (Bcf)	Total Gas (Bcf)	NGLs (Mbbl)(1)	Total Oil Equivalent (Mboe)
PROVED									
Developed Producing	49,987	1,483	14,650	66,120	66.3	807.4	873.8	17,780	229,530
Developed Non-Producing	1,030	—	2,856	3,886	1.0	182.7	183.7	4,230	38,726
Undeveloped	7,056	77	16,438	23,571	7.0	1,156.4	1,163.5	20,583	238,063
TOTAL PROVED	**58,073**	**1,560**	**33,944**	**93,577**	**74.3**	**2,146.6**	**2,220.9**	**42,593**	**506,319**
Probable	18,976	542	17,545	37,063	25.6	1,550.8	1,576.5	29,977	329,784
TOTAL PROVED + PROBABLE	**77,049**	**2,102**	**51,489**	**130,640**	**100.0**	**3,697.4**	**3,797.4**	**72,570**	**836,103**

Company Net Reserves	Light Crude Oil and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Tight Oil (Mbbl)	Total Oil (Mbbl)	Conventional Natural Gas (Bcf)	Shale Gas (Bcf)	Total Gas (Bcf)	NGLs (Mbbl)(1)	Total Oil Equivalent (Mboe)
PROVED									
Developed Producing	46,027	1,594	13,235	60,856	62.0	713.3	775.2	14,236	**204,300**
Developed Non-Producing	922	—	2,480	3,402	0.9	166.3	167.2	3,395	34,671
Undeveloped	6,500	70	14,304	20,873	6.7	1,018.8	1,025.6	16,877	208,680
TOTAL PROVED	**53,449**	**1,664**	**30,018**	**85,131**	**69.6**	**1,898.4**	**1,968.1**	**34,508**	**447,651**
Probable	16,443	558	15,521	32,522	24.1	1,346.9	1,371.0	24,240	285,262
TOTAL PROVED + PROBABLE	**69,892**	**2,222**	**45,539**	**117,653**	**93.7**	**3,245.4**	**3,339.1**	**58,748**	**732,913**

1) Natural Gas Liquids includes Associated Natural Gas Liquids for both Conventional and Shale/Tight Reservoirs, and includes condensate, propane and butane.

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

Before-Tax [1] ($ millions)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
PROVED					
Developed Producing	4,449	3,172	2,475	2,045	1,755
Developed Non-Producing	658	506	411	349	305
Undeveloped	2,690	1,581	973	609	377
TOTAL PROVED	**7,796**	**5,258**	**3,860**	**3,004**	**2,437**
Probable	5,858	3,062	1,883	1,280	927
TOTAL PROVED + PROBABLE	**13,654**	**8,320**	**5,743**	**4,284**	**3,364**
After-Tax [1][2][3] ($ millions)					
PROVED					
Developed Producing	3,758	2,751	2,187	1,832	1,587
Developed Non-Producing	479	368	298	252	220
Undeveloped	1,956	1,104	634	353	175
TOTAL PROVED	**6,194**	**4,222**	**3,119**	**2,437**	**1,982**
Probable	4,268	2,206	1,334	888	629
TOTAL PROVED + PROBABLE	**10,462**	**6,429**	**4,453**	**3,325**	**2,612**

1) Future net revenue values are net of estimated abandonment and reclamation for all wells (both existing and undrilled wells) that have been attributed reserves, including those associated with properties moved to held for sale at December 31, 2017. Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, pipeline, facilities and surface lease reclamations) can be found in ARC's audited financial statements for the year ended December 31, 2017 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.
2) Based on ARC's estimated tax pools at year-end 2017.
3) 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, 2017 and the related Management's Discussion and Analysis should be consulted for information at the business entity level.

Total Future Net Revenues (Undiscounted) - Based on Forecast Prices and Costs

Reserves Category ($ millions)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs [1]	Future Net Revenue before Income Taxes	Income Taxes	Future Net Revenue after Income Taxes
Proved Reserves	17,975	1,887	5,723	2,150	418	7,796	1,603	6,194
Proved Plus Probable Reserves	30,053	3,443	9,215	3,215	527	13,654	3,193	10,462

1) Reflects estimated abandonment and reclamation for all wells (both existing and undrilled wells) that have been attributed reserves, including those associated with properties moved to held for sale at December 31, 2017. This does not account for pipelines, facilities or surface lease reclamations, or for abandonment and reclamation costs for wells with no attributed reserves.

Future Net Revenues by Production Group - Based on Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10% per Year) ($ millions)	Per Unit [1]
Proved Reserves	Light Crude Oil and Medium Crude Oil [2]	954	$17.85/boe
	Heavy Crude Oil [2][3]	28	$16.78/boe
	Tight Oil [2]	966	$32.23/boe
	Conventional Natural Gas [4]	18	$0.77/Mcfe
	Shale Gas [4]	1,962	$1.17/Mcfe
	Other [5]	(68)	$0.00/boe
	Total	**3,860**	**$8.62/boe**
Proved + Probable Reserves	Light Crude Oil and Medium Crude Oil [2]	1,165	$16.67/boe
	Heavy Crude Oil [2][3]	35	$15.55/boe
	Tight Oil 2)	1,495	$32.96/boe
	Conventional Natural Gas [4]	22	$0.76/Mcfe
	Shale Gas [4]	3,111	$1.08/Mcfe
	Other [5]	(85)	$0.00/boe
	Total	**5,743**	**$7.84/boe**

1) Unit values are based on Net Reserves.
2) Including solution gas and other by-products.
3) Per unit revenue positively impacted by a portion of value coming from royalty interest reserves.
4) Including by-products but excluding solution gas and other by-products from oil wells.
5) Includes revenue and expenses not associated with a specific product type.

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, 2017, 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 (1) (%/Year)	Exchange Rate (2) (US$/Cdn$)
Forecast										
2018	59.00	70.25	39.63	65.34	2.20	40.40	53.74	76.42	2.0	0.790
2019	59.00	70.25	45.71	65.34	2.54	36.53	49.18	74.68	2.0	0.790
2020	60.00	70.31	49.81	65.39	2.88	35.93	49.22	74.38	2.0	0.800
2021	63.00	72.84	52.89	67.74	3.24	36.06	50.99	77.16	2.0	0.810
2022	66.00	75.61	55.89	70.32	3.47	36.29	52.93	79.88	2.0	0.820
2023	69.00	78.31	58.82	72.83	3.58	37.59	54.82	82.53	2.0	0.830
2024	72.00	81.93	62.43	76.19	3.66	39.33	57.35	86.14	2.0	0.830
2025	75.00	85.54	66.05	79.55	3.73	41.06	59.88	89.76	2.0	0.830
2026	77.33	88.35	68.86	82.16	3.80	42.41	61.84	92.57	2.0	0.830
2027	78.88	90.22	70.72	83.90	3.88	43.30	63.15	94.43	2.0	0.830
Thereafter	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	2.0	0.830

1) Inflation rates for forecasting costs.
2) Exchange rates used to generate the benchmark reference prices in this table.
3) Prices escalate two per cent per year from 2027.

ARC's weighted average prices realized, prior to hedging, for the year ended December 31, 2017, were Cdn$2.56 per Mcf for shale gas and conventional natural gas, Cdn$61.57 per barrel for tight oil, light crude oil and medium crude oil, Cdn$41.56 per barrel for heavy crude oil, Cdn$62.04 per barrel for condensate and Cdn$29.57 per barrel for natural gas liquids.

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. The forecast price and cost assumptions assumed the continuance of current laws and regulations.
5. All factual data supplied to GLJ was accepted as represented. No field inspection was conducted.
6. 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; through the use of established technology; and within 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 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, 2017, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2017 and as at December 31, 2016 include working interest reserves before royalties payable and without including gross royalties receivable.

In the Proved and Proved plus Probable reconciliations, overall material increases in Extensions, Improved Recovery and Technical revisions were driven by growth on core Montney properties.

Reconciliation of Gross Reserves by Principal Product Type

	Light Crude Oil and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Tight Oil (Mbbl)	Total Oil (Mbbl)	Conven-tional Natural Gas (Bcf)	Shale Gas (Bcf)	Coal Bed Methane (Bcf)	Total Gas (Bcf)	NGLs (Mbbl) [1]	Total Oil Equi-valent 2017 (Mboe)
PROVED										
December 31, 2016	**58,427**	**1,728**	**28,628**	**88,783**	**79.4**	**1,715.1**	**—**	**1,794.5**	**38,064**	**425,927**
Discoveries	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2]	2,889	—	8,082	10,971	2.0	201.9	—	203.9	7,403	52,359
Technical Revisions	1,558	(13)	2,620	4,165	42.9	393.1	—	436.0	1,552	78,381
Acquisitions	—	—	—	—	—	—	—	—	—	4
Dispositions	—	—	—	—	—	(1.2)	—	(1.2)	(32)	(232)
Economic Factors	(616)	(21)	(958)	(1,595)	(2.7)	(17.8)	—	(20.6)	(412)	(5,434)
Production	(4,186)	(134)	(4,428)	(8,747)	(47.3)	(144.4)	—	(191.7)	(3,983)	(44,685)
December 31, 2017	**58,073**	**1,560**	**33,944**	**93,577**	**74.3**	**2,146.6**	**—**	**2,220.9**	**42,593**	**506,319**
PROBABLE										
December 31, 2016	**19,024**	**556**	**15,633**	**35,213**	**27.5**	**1,425.4**	**—**	**1,452.9**	**33,440**	**310,806**
Discoveries	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2]	1,379	—	638	2,017	1.1	181.3	—	182.3	5,674	38,083
Technical Revisions	(1,305)	(2)	825	(482)	(1.5)	(50.0)	—	(51.5)	(9,216)	(18,282)
Acquisitions	—	—	—	—	—	—	—	—	—	1
Dispositions	—	—	—	—	—	(1.6)	—	(1.6)	(43)	(303)
Economic Factors	(122)	(12)	449	315	(1.5)	(4.3)	—	(5.7)	122	(520)
Production	—	—	—	—	—	—	—	—	—	—
December 31, 2017	**18,976**	**542**	**17,545**	**37,063**	**25.6**	**1,550.8**	**—**	**1,576.5**	**29,977**	**329,784**
PROVED PLUS PROBABLE										
December 31, 2016	**77,451**	**2,284**	**44,261**	**123,996**	**106.9**	**3,140.5**	**—**	**3,247.4**	**71,504**	**736,733**
Discoveries	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2]	4,268	—	8,720	12,988	3.1	383.1	—	386.3	13,078	90,441
Technical Revisions	253	(15)	3,445	3,683	41.4	343.0	—	384.5	(7,664)	60,099
Acquisitions	—	—	—	—	—	—	—	—	—	5
Dispositions	—	—	—	—	—	(2.8)	—	(2.8)	(76)	(536)
Economic Factors	(738)	(33)	(509)	(1,280)	(4.2)	(22.1)	—	(26.3)	(290)	(5,954)
Production	(4,186)	(134)	(4,428)	(8,747)	(47.3)	(144.4)	—	(191.7)	(3,983)	(44,685)
December 31, 2017	**77,049**	**2,102**	**51,489**	**130,640**	**100.0**	**3,697.4**	**—**	**3,797.4**	**72,570**	**836,103**

1) Natural Gas Liquids includes Associated Natural Gas Liquids for both Conventional and Shale/Tight Reservoirs.
2) 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 ($ millions)	Proved Plus Probable Reserves ($ millions)
2018	500	621
2019	513	602
2020	450	564
2021	290	612
2022	119	313
Remainder	278	504
Total: Undiscounted	2,150	3,215
Total: Discounted at 10% per Year	1,666	2,413

We expect to fund the development costs of the reserves through a combination of sources including funds from operations, proceeds from property dispositions, debt capacity, and if necessary, the 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 at that time. Undiscounted future development costs ("**FDC**") for proved plus probable undeveloped reserves increased $460 million compared to year-end 2016, to total $3.2 billion at year-end 2017. The change in FDC is mainly attributed to an increase in the booking of future development activities in ARC's core Montney acreage.

Estimates of reserves and future net revenues 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 revenues 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.

Proved Undeveloped Reserves

	Light Crude Oil and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Tight Oil (Mbbl)		Conventional Natural Gas (Bcf)		Shale Gas (Bcf)	
	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
2015	507	5,988	—	84	3,008	7,712	0.5	5.1	166.8	776.7
2016	293	6,088	—	80	9,854	14,078	0.7	8.1	377.1	941.8
2017	2,530	7,056	—	77	6,440	16,438	1.7	7.0	206.6	1,156.4

	Coal Bed Methane (Bcf)		NGLs (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End
2015	NMF	1.2	3,795	15,470	35,205	159,755
2016	—	—	10,507	24,108	83,261	202,656
2017	—	—	7,558	20,583	51,249	238,063

Probable Undeveloped Reserves

	Light Crude Oil and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Tight Oil (Mbbl)		Conventional Natural Gas (Bcf)		Shale Gas (Bcf)	
	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
2015	1,752	10,083	—	29	3,911	11,449	1.4	8.4	195.0	1,034.5
2016	207	3,653	—	28	6,171	9,809	0.3	5.5	506.9	1,151.2
2017	1,255	4,186	—	28	3,033	11,165	0.9	4.6	209.0	1,216.6

	Coal Bed Methane (Bcf)		NGLs (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End
2015	NMF	2.0	5,747	19,169	44,148	214,882
2016	—	—	16,082	28,291	106,991	234,556
2017	—	—	7,968	21,287	47,241	240,188

*NMF: Not Meaningful Figure

As of December 31, 2017, undeveloped reserves represented 47 per cent of total proved reserves and 57 per cent of proved plus probable reserves. Over 90 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 2018 and 2019, focusing on the Dawson, Parkland/Tower, Sunrise and Attachie areas. ARC's 2018 capital program includes infrastructure spending for Sunrise Phase II which is expected to come on-stream by mid-year 2019. Front-end engineering and design work will also be initiated for the Dawson Phase IV gas processing facility, which has received regulatory approval.

The pace of development of the proved and probable undeveloped reserves (both in 2018 and 2019 as well as in years beyond 2019) 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 or changing regulation and/or fiscal or environmental policy); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion in one zone may be delayed until the initial completion from a separate zone 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 AFFECTING RESERVES DATA

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 *Appendix C "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 would 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.

The following table sets forth information respecting future abandonment and reclamation costs recognized in our audited consolidated financial statements for the year ended December 31, 2017 for surface leases, wells, facilities and pipelines for properties to which reserves have been attributed (aggregated at a property level)**:**

Abandonment & Reclamation Costs(1)(2) Escalated at 2.0%	**Undiscounted ($ millions)**	**Discounted at 10%(3) ($ millions)**
Total as at December 31, 2017	967.4	81.5
Anticipated to be paid in 2018	14.5	13.2
Anticipated to be paid in 2019	21.8	18.0
Anticipated to be paid in 2020	21.6	16.2

1) Abandonment and reclamation costs associated with liabilities associated with properties moved to held for sale at December 31, 2017 have been excluded from this summary.
2) Excludes abandonment and reclamation costs for properties with no attributed reserves.
3) Costs have been discounted in our audited consolidated financial statements for the year ended December 31, 2017 at a liability-specific risk-free rate 2.3 per cent.

For more information with respect to our reclamation and abandonment obligations for properties with no attributed reserves, see "*Statement of Reserves Data and Other Oil and Gas Information - Properties with no Attributable Reserves*" in this Annual Information Form.

In addition, see "*Further Information Respecting Abandonment Obligations*" below.

FURTHER INFORMATION RESPECTING ABANDONMENT OBLIGATIONS

Abandonment and reclamation costs are incurred for shut-in and producing wells, facilities and pipelines to restore properties that have been disturbed by ARC's operations to the standard imposed by the applicable regulatory authorities. Abandonment and reclamation costs for our oil and gas development and production assets and exploration and evaluation ("E&E") assets are included in ARC's annual budgeting process for the budget year and a provision for these costs is recognized at the present value of Management's best estimate of expenditures required to settle the liability as at the date of the balance sheet. These ongoing environmental obligations are expected to be provided for with funds from operations. A portion of the liability is settled each year and facilities are scheduled to be decommissioned once all of the wells associated with a particular facility have been abandoned. Our model for estimating the amount and timing of future abandonment and reclamation expenditures was created at an operating area level. Estimated expenditures for each operating area are based on numerous sources, including information provided by provincial regulatory authorities, 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. No estimate of salvage value is netted against the estimated cost. The estimates are reviewed periodically, and any changes are applied prospectively.

The provision for site restoration and abandonment is based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology. For more information, see Note 5 "*Management Judgments and Estimation Uncertainty*" in our audited consolidated financial statements for the year ended December 31, 2017, which are available on our SEDAR profile at www.sedar.com.

As at December 31, 2017 ARC had 3,540 net wells for which we expect to incur abandonment and reclamation costs (4,422 net wells including the wells associated with properties held for sale at December 31, 2017). In estimating the future net revenues disclosed in this Annual Information Form, the GLJ Report deducted $526.9 million (undiscounted) and $54.8 million (10 per cent discount) for abandonment and reclamation costs for all wells (both existing and undrilled wells) that have been attributed proved and probable reserves, including those associated with properties classified as held for sale at December 31, 2017.

The future net revenues estimated in the GLJ Report and disclosed in this Annual Information Form do not contain an allowance for abandonment and reclamation costs for wells, facilities or pipelines for our properties with no attributed reserves. Management has estimated that there is an additional $25.6 million (undiscounted) and $7.8 million (10 per cent discount) not included in these future net revenues for abandonment and reclamation costs related to wells and an additional $24.7 million (undiscounted) and $0.5 million (10 per cent discount) for abandonment and reclamation costs related to facilities and pipelines for our properties with no attributed reserves.

In 2006, ARC committed to a restricted reclamation trust associated with the acquisition of its Redwater property pursuant to which ARC agreed with the vendor of the Redwater property to contribute to such trust certain minimum amounts, totaling approximately $110.0 million over a 50-year period, to fund future environmental and reclamation obligations in respect of the Redwater property, or to expend certain minimum amounts towards discharging these obligations. In accordance with the fund agreement, ARC has contributed total funds of $54.5 million to the restricted reclamation fund as at December 31, 2017. Contributions to the fund will continue at a declining rate through 2055. The balance of the restricted reclamation fund was $36.7 million at December 31, 2017.

Additional information related to our reclamation and abandonment obligations can be found in Note 15 "*Asset Retirement Obligations*" in our audited consolidated financial statements for the year ended December 31, 2017, and under the heading "*Asset Retirement Obligations*" in our management's discussion and analysis for the year ended December 31, 2017, which documents are available on our SEDAR profile at www.sedar.com.

For more information with respect to our reclamation and abandonment obligations for properties with no attributed reserves, see "*Statement of Reserves Data and Other Oil and Gas Information - Properties with no Attributable Reserves*" in this Annual Information Form.

CORE OPERATING AREAS

The following is a description of ARC's principal oil and natural gas properties as at December 31, 2017. Information in respect of gross and net acres and well counts are as at December 31, 2017. 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 as at December 31, 2017 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.

ARC's oil and gas properties described below are all located in the Western Canadian Sedimentary Basin and onshore within the Canadian provinces of British Columbia and Alberta. 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, 2017 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.

British Columbia

Northeast British Columbia

ARC's assets in Northeast British Columbia are predominantly located in the Montney formation. ARC is one of the largest operators in the region with an average working interest of 91 per cent in approximately 247,023 gross hectares (224,926 net hectares), which includes land holdings of 685 net Montney sections in British Columbia. ARC drilled 86 gross operated wells in 2017 within the region, with an average working interest of 100 per cent. ARC also owns and operates approximately 330 MMcf per day of natural gas and 17,500 barrels per day of liquids processing capacity through its facilities in the region, including the Dawson Phase III gas processing and liquids-handling facility, which was brought on-stream in June 2017. The facility was designed to process 90 MMcf per day of natural gas and 7,500 barrels per day of liquids (approximately 50 per cent condensate handling).

Alberta

Northern Alberta

ARC has an average working interest of 79 per cent in the area with approximately 287,412 gross hectares (227,433 net hectares), which includes land holdings of 525 net Montney sections. ARC drilled 21 gross operated wells in 2017 within the region, with an average working interest of 100 per cent.

Pembina

ARC has an average working interest of 79 per cent in approximately 82,105 gross hectares (65,112 net hectares). During 2017, ARC drilled a total of 15 gross operated Cardium horizontal oil wells with an average working interest of 84 per cent.

South Central Alberta

ARC has an average working interest of 82 per cent in approximately 30,560 gross hectares (25,026 net hectares) in the region.

CONTINGENT RESOURCE ESTIMATES

ARC engaged GLJ to provide an updated evaluation of**,** among other things, our Contingent Resources (as defined in Appendix C attached to this Annual Information Form) effective December 31, 2017, for our working interest in our NE BC Montney properties, including lands at Pouce Coupe across the provincial border in Alberta. These Contingent Resources are set forth and described in *Appendix C* attached to this Annual Information Form.

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, 2017.

By Province	Oil Wells [1]				Natural Gas Wells [2]			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
British Columbia	119	118	4	3	414	386	128	116
Alberta	2,313	1,703	1,101	578	480	127	209	86
Total [3]	2,432	1,821	1,105	581	894	513	337	202

1) Includes light crude oil and medium crude oil wells, heavy crude oil wells and tight oil wells.
2) Includes conventional natural gas wells and shale gas wells.
3) Total well count differs from well count provided in our discussion of asset retirement obligations, as this table excludes abandoned, water source, water injection and disposal wells.

PROPERTIES WITH NO ATTRIBUTABLE RESERVES

The following table sets out by district our unproved properties as at December 31, 2017.

Undeveloped Hectares

	Gross	**Net**
British Columbia	169,858	156,379
Alberta	213,766	142,726
Total	383,624	299,105

Unproved properties are lands that have not been assigned reserves; however, in certain of our undeveloped lands, reserves may have been assigned in shallower formations. Undeveloped hectares are mineral agreement specific. The table above includes vertically stacked agreements within the same areal footprint.

ARC has no material work commitments related to our undeveloped hectares in 2018. There are no material expiries in our core holdings in 2018.

Significant Factors or Uncertainties for Properties with No Attributed Reserves

ARC's business model focuses on our core operations, with little to no capital allocated to the acquisition, exploration or development of properties with no attributed reserves. Therefore, there are not expected to be any significant factors or uncertainties that would affect such properties at this time and the abandonment and reclamation costs associated with these properties are not expected to be unusually significant.

For information with respect to our reclamation and abandonment obligations for our properties to which reserves have been attributed, see "*Statement of Reserves Data and Other Oil and Gas Information - Further Information Respecting Abandonment Obligations*" in this Annual Information Form.

FORWARD CONTRACTS AND TRANSPORTATION COMMITMENTS

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 our derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties, including counterparties within our lending syndicate and by continuously monitoring ongoing credit risks.

A summary of our financial contracts in respect of hedging activities can be found in Note 17 *"Financial Instruments and Market Risk Management",* to our audited consolidated financial statements for the year ended December 31, 2017 and in the section under the heading *"Risk Management"* in our Management's Discussion and Analysis for the year ended December 31, 2017, both of which are incorporated by reference into this Annual Information Form.

A part of our ongoing strategy is to secure transportation to ensure our production moves to market over the short and long term. ARC believes that securing firm takeaway capacity is prudent management of our business and as such has secured sufficient takeaway for future growth. Beginning in 2018, our transportation commitments for future physical deliveries of oil, natural gas and natural gas liquids exceed ARC's expected related future production of our proved reserves, based on the GLJ Report. The amount and estimated cost of excess firm takeaway capacity as compared to our proved reserves forecast is presented in the table below:

	0-5 Years	Beyond Five Years
Natural Gas (MMcf/d)	111	115
Crude oil and NGLs (Mbbl/d)	—	5
Estimated Cost (millions)	$51	$223

1) Contracts with renewal rights that have fulfilled their initial term requirement have been removed for calculation purposes.

ARC expects to fulfill these commitments through its ongoing exploration and development activities subject to our ongoing development plans, well performance and disruptions or constraints at facilities and pipelines.

Forecast production of the Company's proved plus probable reserves based on the GLJ Report, is approximately 65 per cent higher than forecast production from proved reserves used for the purposes of calculating the differences and fees described above. If the Company's sales volumes were equivalent to the forecast production of proved plus probable reserves, the amount and estimated cost of excess firm takeaway capacity as compared to our expected related production from our proved plus probable reserves is presented in the table below:

	0-5 Years	Beyond Five Years
Natural Gas (MMcf/d)	49	62
Crude oil and NGLs (Mbbl/d)	—	—
Related fees (millions)	$23	$102

1) Contracts with renewal rights that have fulfilled their initial term requirement have been removed for calculation purposes.

In cases where ARC holds transportation commitments for volume that exceeds its expected future production from proved and proved plus probable reserves, it has identified opportunities where it may reduce its exposure to negative cash flows arising from the settlements of these contract obligations.

Additional disclosure related to such commitments, as well as ARC's other financial contracts as at December 31, 2017, are set forth in Note 21 *"Commitments and Contingencies"* of our audited consolidated financial statements as at and for the year ended December 31, 2017 which have been filed on our SEDAR profile at www.sedar.com, which has been incorporated by reference into this Annual Information Form.

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, acquisitions, and dispositions.

ARC has accumulated $1.9 billion of income tax pools for federal tax purposes as at December 31, 2017. In 2017, ARC recognized current income taxes of $21.3 million related to current period taxable income, offset by a $4.8 million current income tax recovery related to the filing of prior year tax returns. For 2018, ARC expects to recognize current income taxes between zero and five percent of funds from operations; however, this will be dependent on the commodity price environment and capital spending. For more information, please see Note 18 "*Income Taxes*" in our audited consolidated financial statements for the year ended December 31, 2017, which note is incorporated by reference in this Annual Information Form and is found on our SEDAR profile at www.sedar.com.

CAPITAL EXPENDITURES

The following table summarizes capital expenditures (net of incentives and net of certain acquisitions and dispositions, and including capitalized general and administrative expenses) related to our activities for the year ended December 31, 2017:

2017 Capital and Land Expenditures

($ millions)	British Columbia	Alberta	Total
Property Acquisition (Disposition) Costs, Net (1)			
Proved Properties	4.7	0.9	5.6
Undeveloped Properties	(3.1)	—	(3.1)
Exploration Costs (2)	116.7	—	116.7
Development Costs (3)	592.9	206.6	799.5
Corporate Capital Costs	—	11.1	11.1
Total	**711.2**	**218.6**	**929.8**

1) Represents acquisition costs net of disposition proceeds 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 ($74.0 million).
3) Represents additions to oil and gas development and production assets and administrative assets and includes costs of land acquired ($23.6 million).

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following tables set forth the gross and net development wells that we participated in during the year ended December 31, 2017.

By Province	Development Wells (1)		Exploratory Wells(1)		Total (1)(2)	
	Gross	Net	Gross	Net	Gross	Net
British Columbia	86	86.00	—	—	86	86.00
Alberta	39	36.00	1	1.00	40	37.00
Total	**125**	**122.00**	**1**	**1.00**	**126**	**123.00**

1) Number of wells based on rig release dates.
2) ARC did not drill dry holes or service wells for the year ended December 31, 2017.

PRODUCTION ESTIMATES

The following tables set out the GLJ forecast of the volume of production estimated for the year ended December 31, 2018 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 Crude Oil & Medium Crude Oil (bbl/d)		Heavy Crude Oil (bbl/d)		Tight Oil (bbl/d)		Conventional Natural Gas (Mcf/d)		Shale Gas (Mcf/d)		NGLs (bbl/d)		Total (boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Dawson	—	—	—	—	—	—	—	—	256,442	237,064	3,883	3,216	46,623	42,727
Other Properties	11,033	10,241	348	487	13,811	11,393	20,500	18,761	278,956	262,804	6,553	5,099	81,654	74,148
Total Proved	**11,033**	**10,241**	**348**	**487**	**13,811**	**11,393**	**20,500**	**18,761**	**535,398**	**499,868**	**10,436**	**8,315**	**128,277**	**116,874**

TOTAL PROBABLE	Light Crude Oil & Medium Crude Oil (bbl/d)		Heavy Crude Oil (bbl/d)		Tight Oil (bbl/d)		Conventional Natural Gas (Mcf/d)		Shale Gas (Mcf/d)		NGLs (bbl/d)		Total (boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Dawson	—	—	—	—	—	—	—	—	18,707	17,519	233	194	3,351	3,114
Other Properties	289	248	5	14	833	681	828	742	25,918	24,636	530	428	6,114	5,600
Total Probable	**289**	**248**	**5**	**14**	**833**	**681**	**828**	**742**	**44,625**	**42,155**	**763**	**623**	**9,465**	**8,715**

TOTAL PROVED PLUS PROBABLE	Light Crude Oil & Medium Crude Oil (bbl/d)		Heavy Crude Oil (bbl/d)		Tight Oil (bbl/d)		Conventional Natural Gas (Mcf/d)		Shale Gas (Mcf/d)		NGLs (bbl/d)		Total (boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Dawson	—	—	—	—	—	—	—	—	275,149	254,583	4,116	3,410	49,974	45,841
Other Properties	11,321	10,489	353	501	14,644	12,073	21,327	19,502	304,875	287,440	7,083	5,527	87,768	79,748
Total Proved + Probable	**11,321**	**10,489**	**353**	**501**	**14,644**	**12,073**	**21,327**	**19,502**	**580,023**	**542,024**	**11,199**	**8,938**	**137,742**	**125,589**

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 netbacks for the periods indicated below:

Production History	**Quarter Ended 2017**				**Year Ended**
	Mar 31	**June 30**	**Sept 30**	**Dec 31**	**2017**
Average Daily Production (1)					
Light and Medium Crude Oil (bbl/d)	11,745	11,487	10,849	11,665	11,435
Heavy Oil (bbl/d)	825	658	678	826	747
Tight Oil (bbl/d)	11,460	11,668	13,493	12,150	12,198
Conventional Natural Gas (MMcf/d)	18.8	20.1	18.9	20.0	19.5
Shale Gas (MMcf/d)	477.4	463.8	530.7	552.4	506.3
Coal Bed Methane (MMcf/d)	—	—	—	—	—
NGLs (bbl/d) (2)	8,397	8,944	12,906	13,369	10,923
Condensate (bbl/d)	4,504	4,253	6,815	6,989	5,650
Other NGLs (bbl/d) (3)	3,893	4,691	6,091	6,380	5,273
Total (boe/d)	115,129	113,410	129,526	133,409	122,937
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	61.95	60.19	54.78	67.31	61.17
Heavy Oil ($/bbl)	33.89	40.86	41.72	49.45	41.56
Tight Oil (bbl/d)	62.85	59.93	54.92	68.49	61.36
Conventional Natural Gas (MMcf/d)	3.12	3.06	1.88	2.25	2.57
Shale Gas (MMcf/d)	3.10	2.98	2.00	2.27	2.56
Coal Bed Methane (MMcf/d)	—	—	—	—	—
NGLs ($/bbl) (2)	46.57	42.35	42.05	53.06	46.37
Condensate ($/bbl)	64.44	60.08	54.28	69.27	62.04
Other NGLs (bbl/d) (3)	25.91	26.27	28.37	35.31	29.57
Total ($/boe)	29.63	28.63	23.29	27.58	27.16
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	4.40	5.90	4.54	4.43	4.82
Heavy Oil ($/bbl)	1.54	1.70	1.51	1.56	1.57
Tight Oil (bbl/d)	9.09	10.43	8.56	10.50	9.61
Conventional Natural Gas (MMcf/d)	(0.47)	(0.04)	(0.14)	(0.36)	(0.25)

Shale Gas (MMcf/d)	0.19	0.14	0.03	0.05	0.10
Coal Bed Methane (MMcf/d)	—	—	—	—	—
NGLs ($/bbl) [2]	5.92	6.55	4.73	6.47	5.87
Condensate ($/bbl)	7.41	9.45	5.38	7.35	7.16
Other NGLs (bbl/d) [3]	4.21	3.93	4.01	5.50	4.50
Total ($/boe)	2.49	2.76	1.85	2.15	2.29

Production History - continued		**Quarter Ended 2017**			**Year Ended**
	Mar 31	**June 30**	**Sept 30**	**Dec 31**	**2017**
Operating Expenses [4][5]					
Light and Medium Crude Oil ($/bbl)	24.89	27.40	23.08	22.63	24.50
Heavy Oil ($/bbl)	8.69	12.65	10.85	10.68	10.61
Tight Oil (bbl/d)	3.88	5.40	4.17	4.74	4.54
Conventional Natural Gas (MMcf/d)	4.91	3.03	3.93	3.01	3.67
Shale Gas (MMcf/d)	0.62	0.59	0.69	0.63	0.63
Coal Bed Methane (MMcf/d)	—	—	—	—	—
NGLs ($/bbl) [2]	6.81	6.40	6.35	5.54	6.24
Condensate ($/bbl)	6.67	5.76	6.38	5.35	6.16
Other NGLs (bbl/d) [3]	6.93	6.90	6.32	5.74	6.33
Total ($/boe)	6.74	6.65	6.33	6.01	6.41
Transportation Paid					
Light and Medium Crude Oil ($/bbl)	1.50	1.50	1.51	1.42	1.48
Heavy Oil ($/bbl)	0.55	0.59	0.63	0.46	0.55
Tight Oil (bbl/d)	3.88	3.86	4.45	4.11	4.09
Conventional Natural Gas (MMcf/d)	0.52	0.53	0.43	0.44	0.48
Shale Gas (MMcf/d)	0.33	0.42	0.31	0.33	0.35
Coal Bed Methane (MMcf/d)	—	—	—	—	—
NGLs ($/bbl) [2]	5.55	5.17	5.54	5.10	5.33
Condensate ($/bbl)	3.22	2.93	3.48	3.56	3.35
Other NGLs (bbl/d) [3]	8.25	7.21	7.85	6.79	7.46
Total ($/boe)	2.42	2.78	2.47	2.44	2.52
Netback Received [6]					
Light and Medium Crude Oil ($/bbl)	31.16	25.38	25.66	38.83	30.37
Heavy Oil ($/bbl)	23.11	25.92	28.73	36.75	28.83
Tight Oil (bbl/d)	46.00	40.23	37.74	49.14	43.11
Conventional Natural Gas (MMcf/d)	(1.85)	3.08	(2.34)	(0.84)	(0.41)
Shale Gas (MMcf/d)	1.97	1.69	0.97	1.26	1.45
Coal Bed Methane (MMcf/d)	—	—	—	—	—
NGLs ($/bbl) [2]	28.29	24.23	25.43	35.95	28.93
Condensate ($/bbl)	47.14	41.94	39.04	53.01	45.37
Other NGLs (bbl/d) [3]	6.52	8.23	10.19	17.28	11.28
Total ($/boe)	17.98	16.44	12.64	16.98	15.94

1) Before deduction of royalties and including royalty interests.
2) NGLs as defined by GLJ which includes condensate, butane, ethane and propane.
3) Other NGLs or other natural gas liquids as defined by ARC in external reporting includes butane, ethane and propane but excludes condensate.
4) 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.
5) Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.
6) Refer to the section entitled "Non-GAAP Measures" contained within our Management's Discussion and Analysis for the year ended December 31, 2017, which note is incorporated in this Annual Information Form by reference and is found on our SEDAR profile at www.sedar.com.

British Columbia and Alberta account for approximately 72 per cent and 28 per cent, respectively, of the total production disclosed above. For more information, see *"Statement of Reserves Data and Other Oil and Gas Information"*.

MARKETING ARRANGEMENTS

Below are details on marketing arrangements for our natural gas, natural gas liquids and crude oil production. For more information on financial contractual obligations relating to ARC's transportation agreements please see Note 21 "*Commitments and Contingencies*" in our audited consolidated financial statements for the year ending December 31, 2017, which note is incorporated by reference in this Annual Information Form and is found on our SEDAR profile at www.sedar.com

Natural Gas

During 2017, 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 2017 was $2.56 per Mcf before hedging as compared to $2.23 per Mcf before hedging for 2016. This price was achieved with a portfolio mix that on average through the year, before hedging, received AECO index-based pricing for 60 per cent, Western Canadian Station 2 index based pricing for six per cent, Midwest based pricing for 31 percent, Pacific Northwest based pricing for two per cent and Dawn based pricing of one per cent of total production, respectively.

Our natural gas sales portfolio is directed towards liquid markets and pricing terms that allow us to reduce price volatility .

Crude Oil and Natural Gas Liquids

Our liquids production in 2017 was comprised of approximately 56 per cent light quality crude oil (greater than 35° API), 10 per cent medium quality crude oil (25° to 35° API), one per cent heavy quality crude (less than 25° API) and 33 per cent condensate and natural gas liquids.

During 2017, our average sales prices before hedging were $61.57 per barrel for light and medium crude oil, $41.56 per barrel for heavy crude oil and $46.37 per barrel for natural gas liquids including free condensate; these prices compare to 2016 prices of $50.69 per barrel for light and medium crude oil, $32.62 per barrel for heavy crude oil and $30.89 per barrel for natural gas liquids including free condensate.

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 - Market Access Constraints and Transportation Interruptions"*.

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 multi-year contracts at market-based pricing. Industry pricing benchmarks for crude oil and natural gas liquids are continuously monitored to ensure optimal netbacks.

CORPORATE SOCIAL RESPONSIBILITY

ARC is committed to operating in a responsible manner and integrating principles of responsible development into all parts of our business. Our Corporate Code of Conduct, Environmental and Health and Safety Policies guide our activities in these areas. These policies are available on our website at www.arcresources.com.

We published our most recent biennial Sustainability Report in August 2016 and a new report will be published in August 2018, detailing our efforts and performance in environmental management, health and safety, leadership culture, community investment, stakeholder engagement and corporate governance. The report can be viewed at www.arcresponsibility.com.

SHARE CAPITAL OF ARC RESOURCES

The authorized capital of ARC Resources is an unlimited number of Common Shares without nominal or par value and 50,000,000 preferred shares without nominal or par value issuable in series of which 353,461,375 Common Shares and no preferred shares are outstanding as at December 31, 2017.

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

ARC borrows 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 the ratio of net debt to annualized funds from operations between one to 1.5 times and to target net debt to be 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 may comprise 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.

As at December 31, 2017, we had credit facilities consisting of a $950 million, financial covenant based credit facility with a syndicate of major chartered banks, a $40 million working capital facility with our agent bank, a $15 million letter of credit facility with our agent bank, a $25 million letter of credit facility with another major chartered bank and member of the syndicate, and US$696.0 million and $40.0 million of senior notes outstanding. ARC had a net debt balance of $728.0 million outstanding at December 31, 2017, comprised of $911.3 million of long-term debt and a working capital surplus of $183.3 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 1, 2017, the credit facility was extended for another year at current pricing terms of the existing facility. The current maturity date of the credit facility is November 8, 2021.

The senior notes outstanding were issued in seven 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 3.50 trailing 12 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 12 month net income before non-cash items, income tax and interest expense; and
- Long-term debt and letters of credit not to exceed 55 per cent of Shareholders' equity and long-term debt, letters of credit and subordinated debt.

ARC is in compliance in all material respects with the terms of the agreements governing the credit facilities described above, and has maintained this status throughout the Corporation's 21 year history.

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. For more information, reference is made to Note 14 "*Long-term Debt*" of our audited consolidated financial statements for the year ended December 31, 2017, which note is incorporated by reference in this Annual Information Form and is found on our SEDAR profile at www.sedar.com.

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

STOCK DIVIDEND PROGRAM AND DIVIDEND REINVESTMENT PLAN

On February 8, 2017, ARC announced the elimination of the DRIP and SDP. Elimination of both programs was applied beginning with the April 17, 2017 dividend payment to Shareholders on record on March 31, 2017. Shareholders that were enrolled in either the DRIP or SDP now automatically receive dividend payments in the form of cash.

Prior to elimination of these programs, the SDP enabled 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 were issued at the prevailing market price, as defined under the SDP, with no broker fees or commissions. The SDP was generally available to most Shareholders and was expected to provide many Shareholders with Canadian income tax treatment more favourable than the DRIP.

The DRIP enabled Canadian Shareholders to have their dividends reinvested into additional Common Shares of ARC. Common Shares issued under the DRIP were issued at the prevailing market price, as defined under the DRIP, with no broker fees or commissions.

DIRECTORS AND EXECUTIVE OFFICERS

DIRECTORS

The name, municipality, province and country of residence, positions held, period during which such positions has been held and principal occupation of each Director of ARC Resources during the past five years as at December 31, 2017 are set out below.

Directors		
Name and Municipality of Residence	**Director Since [1]**	**Principal Occupation During Past Five Years**
Harold N. Kvisle Calgary, Alberta Canada	2009 (Chair) Independent	Mr. Kvisle is the Chairman of ARC's Board, a position he has held since January 1, 2016. Prior to May 2015, he was President and Chief Executive Officer of Talisman Energy, and prior to September 2012, he was an independent business person.
David R. Collyer Calgary, Alberta Canada	2016 Independent	Mr. Collyer is an independent business person. Prior to 2014, Mr. Collyer was the President and Chief Executive Officer of the Canadian Association of Petroleum Producers.
John P. Dielwart [2] Calgary, Alberta, Canada	1996 Independent	Mr. Dielwart is currently the Vice-Chairman of ARC Financial Corp, Canada's largest energy focused private equity manager.
Fred J. Dyment Calgary, Alberta, Canada	2003 Independent	Mr. Dyment is an independent business person.
Timothy J. Hearn Calgary, Alberta, Canada	2011 Independent	Mr. Hearn is an independent business person.
James C. Houck Santa Barbara, California, USA	2008 Independent	Mr. Houck is an independent business person.
Kathleen M. O'Neill Toronto, Ontario, Canada	2009 Independent	Ms. O'Neill is an independent business person.
Herbert C. Pinder, Jr. Saskatoon, Saskatchewan, Canada	2006 Independent	Mr. Pinder is an independent business person.
William G. Sembo Calgary, Alberta, Canada	2013 Independent	Mr. Sembo is an independent business person.
Nancy Smith [3] Calgary, Alberta, Canada	2016 Independent	Ms. Smith is a Director and Investment Committee Member of ARC Financial Corp, Canada's largest energy focused private equity manager.
Myron M. Stadnyk Calgary, Alberta, Canada	2013 Management Director	Mr. Stadnyk is the President and Chief Executive Officer of ARC Resources.

1) The term of each director is until the next annual meeting of ARC Resources, which is scheduled to be held on May 3, 2018.
2) Mr. Dielwart, who is the Chair of the Health, Safety and Environment Committee and is a member of the Reserves Committee, retired from the position of CEO of ARC Resources effective January 1, 2013 but remains as a director. On February 8, 2018, the Board of Directors deemed Mr. Dielwart to now be independent five years after his resignation as CEO of ARC.
3) Ms. Smith was a director of Corinthian Oil Corp. ("Corinthian") until September 19, 2017 when it was acquired by a third party. Corinthian was solvent, has positive working capital and no long-term debt when it was sold. Ms. Smith resigned her directorship on closing of the transaction. Corinthian was amalgamated with a wholly-owned subsidiary of the third party and the amalgamated subsidiary subsequently guaranteed debt of the third party purchaser. In the following year, the third party filed a notice of intention under the *Bankruptcy and Insolvency Act* (which ultimately included its subsidiaries as a result of the guarantees provided by the subsidiaries) pursuant to which a receiver and manager of its assets was appointed under a court order and the third party and its subsidiaries were declared bankrupt.

All of the current Directors of ARC Resources were elected on May 4, 2017 to hold office until the next annual meeting of ARC Resources. The next annual meeting is scheduled to be held on May 3, 2018.

As at December 31, 2017, the Directors and officers of ARC Resources, as a group, beneficially owned, or controlled or directed, directly or indirectly, 5,445,877 Common Shares or approximately 1.5 per cent of the outstanding Common Shares.

EXECUTIVE OFFICERS

The name, municipality, province and country of residence, position held and principal occupation during the past five years of each executive officer of ARC Resources as at December 31, 2017 are set out below.

Officers	
Name and Municipality of Residence	**Office Held and Principal Occupation During Past Five Years**
Myron M. Stadnyk Calgary, Alberta, Canada	**President and Chief Executive Officer** Mr. Stadnyk's biographical information is included under "Directors"
P. Van R. Dafoe Calgary, Alberta, Canada	**Senior Vice President and Chief Financial Officer** Mr. Dafoe is the Senior Vice President and Chief Financial Officer. Prior to February 2014, he was the Senior Vice President, Finance.
Terry M. Anderson Calgary, Alberta, Canada	**Senior Vice President and Chief Operating Officer** Mr. Anderson is the Senior Vice President and Chief Operating Officer. Prior to January 2014, he was the Senior Vice President, Engineering.
Bevin M. Wirzba Calgary, Alberta, Canada	**Senior Vice President, Business Development and Capital Markets** Mr. Wirzba is the Senior Vice President, Business Development and Capital Markets. Prior to January 2016, he was a Managing Director at RBC Dominion Securities.
Kristen J. Bibby Calgary, Alberta, Canada	**Vice President, Finance** Mr. Bibby is the Vice President, Finance. Prior to August 2014, he was Vice President, Finance and Chief Financial Officer at Verano Energy Limited.
Sean R. A. Calder Calgary, Alberta, Canada	**Vice President, Production** Mr. Calder is the Vice President, Production.
Larissa M. Conrad (1) Calgary, Alberta, Canada	**Vice President, Engineering and Planning** Ms. Conrad is the Vice President, Engineering and Planning. Prior to February 2014, she was Manager, Engineering South.
Christopher D. Baldwin Calgary, Alberta, Canada	**Vice President, Geosciences** Mr. Baldwin is the Vice President Geosciences. Prior to 2017, he was the Manager, Geosciences North.
Ryan V. Berrett Calgary, Alberta, Canada	**Vice President, Marketing** Mr. Berrett is the Vice President, Marketing. Prior to January 2017, he was the Manager, Marketing.
Wayne D. Lentz (2) Calgary, Alberta, Canada	**Vice President, Business Analysis** Mr. Lentz is the Vice President, Business Analysis. Prior to December 2016, he was the Vice President, Strategy and Business Development.
Armin Jahangiri Calgary, Alberta, Canada	**Vice President, Operations** Mr. Jahangiri is the Vice President, Operations. Prior to March 2017, he was the Manager, Engineering North.
Lisa A. Olsen Calgary, Alberta, Canada	**Vice President, Human Resources** Ms. Olsen is the Vice President, Human Resources. Prior to January 2016, she was the Manager, Human Resources.
Grant A. Zawalsky (3) Calgary, Alberta, Canada	**Corporate Secretary** Mr. Zawalsky is the Managing Partner at Burnet, Duckworth & Palmer LLP (law firm)

1) Larissa M. Conrad's title changed to Vice President, Engineering and Planning on January 1, 2017.
2) Wayne D. Lentz's title changed to Vice President, Business Analysis on January 1, 2017.
3) Grant A. 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 February 8, 2018.

Name of Director	Audit	Reserves	Risk	Human Resources & Compensation	Policy & Board Governance	Health, Safety & Environment
Independent Directors						
John P. Dielwart [(1)]		√				Chair
David R. Collyer			√			√
Fred J. Dyment			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				√		√
Nancy Smith	√		√			

1) Mr. Dielwart, who is the Chair of the Health, Safety and Environment Committee and is a member of the Reserves Committee, retired from the position of CEO of ARC Resources effective January 1, 2013 but remains as a director. On February 8, 2018, the Board of Directors deemed Mr. Dielwart to now be independent five years after his resignation as CEO of ARC.

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

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 is considered to be a non-independent director.

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 strategic and management responsibility for the Corporation. Mr. Stadnyk joined ARC in 1997, as the Corporation'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. 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 and the University of Saskatchewan Engineering Alumni Fund.

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

Mr. Dafoe is Senior Vice President and Chief Financial Officer of ARC Resources and oversees the finance, treasury, accounting, tax, risk management and information technology teams at ARC. Prior to being appointed to the role of Senior Vice President and Chief Financial Officer in 2014, Mr. Dafoe was the Senior Vice President, Finance at ARC Resources. Mr. Dafoe has over 30 years of experience in the oil and gas industry and joined ARC in 1999 as Controller. He is a member of the Alberta Chartered Professional Accountants and has a Bachelor of Commerce (Honours) degree from the University of Manitoba. Mr. Dafoe 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

Bevin M. Wirzba, P. Eng., MBA

Mr. Wirzba is Senior Vice President, Business Development and Capital Markets of ARC Resources and is responsible for ARC's acquisition, disposition, land, business development and marketing activities and all facets of investor relations, communications and corporate governance. He has over 20 years of upstream and midstream technical and commercial experience including strategic advisory, investment analysis, project development, and merger, acquisition and divestiture evaluation and execution. Prior to joining ARC in 2016, Mr. Wirzba spent 10 years in the energy advisory and capital markets business of a global investment bank as a Managing Director. Prior thereto, he spent 12 years with a major multi-national corporation working in both North America and internationally. Mr. Wirzba holds a Bachelor of Science in Civil Engineering from the University of Alberta, has a Master in Business Administration from the Edinburgh Business School and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Christopher (Chris) D. Baldwin, P. Geol.

Mr. Baldwin is Vice President, Geosciences of ARC Resources and is responsible for the execution of ARC's geophysical and geological activities. Mr. Baldwin joined ARC in 2009 and has over 15 years of experience in oil and gas exploration, development, geology and geophysics. Prior to joining ARC, Mr. Baldwin held positions with large and intermediate oil and gas companies. Mr. Baldwin holds a Bachelor of Science in Geology from the University of Calgary and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Ryan V. Berrett, B. MGMT, MBA

Mr. Berrett is Vice President, Marketing of ARC Resources and coordinates all marketing activities to ensure market access for ARC's production. He has over 15 years of accounting, finance and marketing experience, having started his career at ARC in 2003. Mr. Berrett has led ARC's marketing activities since 2010. Mr. Berrett holds a Bachelor of Management degree from the University of Lethbridge and an Executive MBA in Global Energy from the University of Calgary's Haskayne School of Business.

Kristen (Kris) J. Bibby, B. Comm., CPA, CA

Mr. Bibby is Vice President, Finance of ARC Resources and is responsible for ARC's financial risk and research, treasury and information technology related activities. He has over 19 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 Alberta Chartered Professional Accountants.

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

Mr. Calder is Vice President, Production of ARC Resources, and manages all aspects of field production operations. He has over 19 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 and Planning of ARC Resources with responsibility for all engineering and strategic planning activities. Ms. Conrad joined ARC in 2011 and has over 19 years of experience in reservoir, exploration, development and production engineering, as well as government and regulatory relations. Prior to joining ARC, she worked at 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).

Armin Jahangiri, P.Eng.

Mr. Jahangiri is Vice President, Operations of ARC Resources and is responsible for overseeing the facilities, drilling and completions, health and safety, and the environment and regulatory teams. He has over 20 years of extensive industry experience in operations and major project development and execution both in North America and internationally. Mr. Jahangiri joined ARC in 2014, and since this time has taken on roles of increasing responsibility. Prior to joining ARC, he worked with a major Canadian oil and gas producer and a global oilfield services company. Mr. Jahangiri holds a Bachelor of Science in Mechanical Engineering from the Shariff University of Technology, and a Master of Engineering in Reservoir Characterization from the University of Calgary. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Wayne D. Lentz, P. Eng.

Mr. Lentz is Vice President, Business Analysis 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 exploration and production 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).

Lisa A. Olsen, BA

Ms. Olsen is Vice President, Human Resources of ARC Resources, and oversees ARC's human resources, office services and records information management functions while supporting ARC's high-performance culture. Ms. Olsen joined ARC in 2008 and has over 19 years of experience in Human Resources. Prior to joining ARC, Ms. Olsen spent over 10 years leading the human resources functions in both a Canadian oil & gas organization as well as for a major international consumer brand. Ms. Olsen has a Bachelor of Communications from Simon Fraser University and an HR Management Certificate from the BC Institute of Technology.

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 is currently a Director for a number of public and private energy companies including NuVista Energy, PrairieSky Royalty Ltd., Whitecap Resources and Zargon Oil and Gas.

AUDIT COMMITTEE DISCLOSURES

National Instrument 52-110 *Audit Committees* ("**NI 52-110**") has mandated certain disclosures for inclusion in this Annual Information Form. The text of the Audit Committee's mandate is attached as Appendix D to this Annual Information Form.

MEMBERS OF THE AUDIT COMMITTEE

As of December 31, 2017, the members of the Audit Committee were Kathleen O'Neill (Chair), James C. Houck and Nancy Smith; each is independent and financially literate within the meaning of NI 52-110. Additionally, Ms. Kathleen O'Neill and Ms. Nancy Smith are considered to be financial experts, having accounting and related financial management experience.

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 LLP. 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 CPA (Chartered Professional Accountants of Canada) and the Canadian Public Accountability Board. Ms. O'Neill is the past Chair of St. Joseph's Health Centre and St. Joseph's Health Center Foundation of Toronto. In 2014, 2015 and 2016, Ms. O'Neill was awarded Canada's Most Powerful Women: Top 100 Award by the Women's Executive Network and was inducted into the Hall of Fame in 2017.

James C. Houck

Mr. Houck has over 40 years of diversified experience in the oil and gas industry. Most recently, he held the position as President, Chief Executive Officer and Director of the Churchill Corporation, a construction and industrial services company. Previously, he was President, Chief Executive Officer and Director 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 upstream oil and gas operations. Mr. Houck has a Bachelor of Engineering Science from Trinity University in San Antonio and a Master in Business Administration from the University of Houston.

Nancy L. Smith

Ms. Smith is a Director and member of the Investment Committee of ARC Financial Corp., Canada's largest energy focused private equity manager. Prior to joining ARC Financial in 1999, she held executive positions in finance and upstream marketing at a Canadian integrated energy company and spent the first five years of her career in corporate banking. Ms. Smith received a Master of Business Administration and a Bachelor of Arts (Economics) from the University of Alberta, and has an ICD.D designation from the Institute of Corporate Directors.

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.

PricewaterhouseCoopers LLP acted as ARC’s external auditor for the fiscal year ended December 31, 2017. Deloitte LLP acted as ARC's external auditor for the fiscal year ended December 31, 2016. The following is a summary of the external audit and non-audit services fees by category.

Summary of External Audit and Non-Audit Service Fees		2016		2017
Audit Fees (1)	$	694,430	$	808,740
Audit Related Fees (2)	$	—	$	9,630
Tax Fees (3)	$	14,499	$	34,101
All Other Fees (4)	$	17,452	$	58,946

1) 2017 audit fees include $125,190 extra billing by Deloitte LLP related to the December 31, 2016 audit.
2) 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.
3) The aggregate fees billed by our external auditor for professional services for various tax advice.
4) Includes 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, as well as fees related to the audit of ARC’s Extractive Sector Transparency Measures Act report.

In keeping with ARC's commitment to best practices in corporate governance, ARC conducted a comprehensive review of its external auditors in 2015. Following the completion of the comprehensive review, in 2016, a tender process was completed for the selection of our auditor and the Board of Directors (on the recommendation of the Audit Committee) determined that PricewaterhouseCoopers LLP was to be appointed as ARC’s auditor for the 2017 fiscal year and received Shareholder approval on May 4, 2017. Additional documents related to the change of auditor, being the Change of Auditor Notice and the acknowledgements of that notice by PricewaterhouseCoopers LLP and Deloitte LLP, can be found under the Corporation's profile on SEDAR. There were no “reportable events” within the meaning of NI 51-102.

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 executive officer, or to our knowledge any person or company that beneficially owns, or who exercises control or direction over, directly or indirectly, 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 15^{th} 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 expenditures, 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 - Dividends*".

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:

Dividends	**2017**	**2016**	**2015**
January	$0.05	$0.10	$0.10
February	$0.05	$0.05	$0.10
March	$0.05	$0.05	$0.10
April	$0.05	$0.05	$0.10
May	$0.05	$0.05	$0.10
June	$0.05	$0.05	$0.10
July	$0.05	$0.05	$0.10
August	$0.05	$0.05	$0.10
September	$0.05	$0.05	$0.10
October	$0.05	$0.05	$0.10
November	$0.05	$0.05	$0.10
December	$0.05	$0.05	$0.10
Total	**$0.60**	**$0.65**	**$1.20**

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 in 2017 of the Common Shares on the TSX for the periods indicated (as quoted by Bloomberg):

Toronto Stock Exchange (1)	High	Low	Volume
January	23.03	20.10	19,024,724
February	21.60	19.48	25,082,062
March	20.08	18.60	25,448,108
April	19.27	17.92	25,662,099
May	18.58	16.86	28,291,861
June	17.83	16.33	25,996,575
July	17.81	16.72	16,357,293
August	16.98	15.76	18,490,995
September	18.23	16.24	27,629,409
October	17.21	15.21	19,998,666
November	17.77	15.27	26,012,913
December	16.28	13.88	23,069,942

(1) Prior to 2017, trading statistics had previously been reported to show trading activity for all Canadian exchanges.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments where the companies have assets or operations. While these regulations do not affect the Corporation's operations in any manner that is materially different than they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although governmental legislation is a matter of public record, the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

ARC holds interests in crude oil and natural gas properties, along with related assets, in the Canadian provinces of Alberta and British Columbia. ARC's assets and operations are regulated by administrative agencies deriving authority from underlying legislation. Regulated aspects of the Corporation's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Western Canada.

PRICING AND MARKETING

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers, which results in the market determining the price of crude oil. Worldwide supply and demand factors primarily determine crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

The price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Condensate and Other Natural Gas Liquids

The price of condensate and other natural gas liquids such as ethane, butane and propane ("NGLs") sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

EXPORTS FROM CANADA

Crude oil, natural gas and NGLs exports from Canada are subject to the *National Energy Board Act* (Canada) (the "**NEB Act**") and the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). The NEB Act and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. To obtain a crude oil export licence, a mandatory public hearing with the National Energy Board (the "**NEB**") is required, which is no longer the case for natural gas and NGLs. For natural gas and NGLs, the NEB uses a written process that includes a public comment period for impacted persons. Following the comment period, the NEB completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. All crude oil, natural gas and NGLs licences require the approval of the cabinet of the Canadian federal government.

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from the cabinet of the Canadian federal government. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m3 per day.

As to price, 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 federal government.

ARC does not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline or other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and political factors. The transportation capacity deficit is not likely to be resolved quickly given the significant length of time required to complete major pipeline or other transportation projects once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

TRANSPORTATION CONSTRAINTS AND MARKET ACCESS

Producers negotiate with pipeline operators (or other transport providers) to transport their products, which may be done on a firm or interruptible basis. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low pricing relative to other markets in the last several years. Transportation availability is highly variable across different areas and regions, which can determine the nature of transportation commitments available, the numbers of potential customers that can be reached in a cost-effective manner and the price received.

Developing a strong network of transportation infrastructure for crude oil, natural gas and NGLs, including by means of pipelines, rail, marine and trucks, in order to obtain better access to domestic and international markets has been a significant challenge to the Canadian crude oil and natural gas industry. Improved means of access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, would help to alleviate the pressures of pricing discussed. Several proposals have been announced to increase pipeline capacity out of Western Canada, to reach Eastern Canada, the United States and international markets via export shipping terminals on the west coast of Canada. While certain projects are proceeding, the regulatory approval process as well as economic and political factors for transportation and other export infrastructure has led to the delay of many pipeline projects or their cancellation altogether.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the NEB and the cabinet of the federal government. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government recently introduced draft legislation to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes to the draft legislation will be made before the legislation is brought into force. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to extensive review and challenge by provincial and municipal governments as well as court challenges on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects.

THE NORTH AMERICAN FREE TRADE AGREEMENT AND OTHER TRADE AGREEMENTS

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. Under the terms of NAFTA, Canada remains 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 Canada 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. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

In 2017, the United States government announced its intention to renegotiate NAFTA. As a result, Canada, the United States and Mexico began renegotiating the terms of NAFTA in mid-2017. The United States has also suggested that it might give notice of the termination of NAFTA if it is not satisfied with the outcome of the renegotiations. If the United States does give notice of its intent to terminate or withdraw from NAFTA, the earliest such termination or withdrawal could occur would be six months after such notice is given. The renegotiations are still underway and the outcome of such negotiations remain unclear, but as the United States remains by far Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, any changes to, or termination of, NAFTA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In addition, Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The text of CPTPP has not been finalized or published and the agreement remains subject to ratification by the governments of each of the countries involved. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

LAND TENURE

The respective provincial governments (i.e. the Crown) predominantly own the mineral rights to crude oil and natural gas located in Western Canada. Provincial governments grant rights to explore for and produce crude 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. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. The leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

Each of the provinces of Alberta and British Columbia have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. Additionally, the provinces of Alberta and British Columbia have shallow rights reversion for shallow, non-productive geological formations for new leases and licences.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in the provinces of Alberta and British Columbia. In each of the provinces of Alberta and British Columbia approximately 19% and 6%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("IOGC"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable indigenous peoples, for exploration and production of crude oil and natural gas on indigenous reservations.

ROYALTIES AND INCENTIVES

General

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 through negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes. Royalties from production on Crown lands are determined by government regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable 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. The majority of ARC's assets are on Crown lands.

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

The following is a description of key royalty programs that are applicable to ARC in the jurisdictions in which we operate. This is not meant to be a fulsome description of all royalty programs; please refer to the respective Province's websites for full royalty details.

Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF took effect on January 1, 2017. Wells drilled prior to January 1, 2017 continue to be governed by the prior "Alberta Royalty Framework" (the "**ARF**") for a period of 10 years, until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed five per cent royalty applies until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, the royalty rate will move to a sliding scale (based on volume and price) with a minimum gross royalty rate of five per cent. The downward adjustment of the royalty rate in the mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

<table>
<tr><th colspan="5">Alberta Royalty Regimes Summary</th></tr>
<tr><th>Royalty Regime</th><th>Product</th><th>Incentive Period</th><th>Post Incentive or Mid-Life (MRF)</th><th>Mature Phase (MRF)</th></tr>
<tr><td rowspan="3">ARF - Royalty formulas base on price and production</td><td>Oil</td><td rowspan="3">5%</td><td colspan="2">0% to 40%</td></tr>
<tr><td>Gas</td><td colspan="2">5% to 36%</td></tr>
<tr><td>Liquids - C3 & C4 / C5+</td><td colspan="2">Flat 30% / Flat 40%</td></tr>
<tr><td rowspan="3">MRF - Royalty formulas based on price with a reduction for lower production during the mature phase</td><td>Oil / Cond / C5+</td><td rowspan="3">Pre-payout 5%</td><td>10% to 40%</td><td rowspan="3">Minimum 5%</td></tr>
<tr><td>Gas</td><td>5% to 36%</td></tr>
<tr><td>C3 /C4</td><td>10% to 36%</td></tr>
</table>

British Columbia

The royalty payable on oil produced on Crown lands depends on the type and vintage of the oil, the quantity of oil produced in a month, the value of that oil and any applicable royalty exemptions. ARC's oil wells qualify for the lowest vintage royalty rates available reflecting the higher unit costs of both exploration and extraction.

The royalty payable on 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 gas wells, the royalty rate depends on the date of acquisition of the tenure rights and the spud date of the well. The royalties payable on natural gas liquids produced on Crown lands are levied at a flat rate of 20 per cent of the sales volume.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's natural gas wells. Important programs applicable to our key properties are:

- *Deep Well Royalty Credit Program,* which provides a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, and is well specific based on drilling and completion depths.
- 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.

ENVIRONMENTAL REGULATION

The crude oil and natural gas industry is subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are 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. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry which may have a material adverse impact on the Corporation.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

On November 29, 2016, the Government of Canada approved, subject to a number of conditions, the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as the replacement of Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline were satisfied, however the new Government of British Columbia has more recently indicated a need to conduct studies before diluted bitumen could be shipped through the pipeline. Additionally, the new administration in the United States has indicated a willingness to revisit other previously rejected pipeline projects.

On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the Canadian Energy Regulator ("CER"). Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "Agency") would replace the Canadian Environmental Assessment Agency. It appears that additional categories of projects may be included within the new impact assessment process, such as large-scale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders such as the public and indigenous groups prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. As to the proposed CER, many of its activities would be similar to the NEB, albeit with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The eventual effects of the proposed regulatory scheme on proponents of major projects remains unclear.

On May 12, 2017, the Government of Canada introduced Bill C-48 - *An Act respecting the regulation of vessels that transport crude oil or persistent oil to or from ports or marine installations located along British Columbia's north coast*. If passed, the proposed moratorium on crude oil tankers on British Columbia's north coast will impose penalties on persons or vessels that contravene the prohibition against carrying crude oil in the area designated in the bill.

Alberta

The Alberta Energy Regulator (the "**AER**") is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. 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 a single regulator is 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.

While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

The Ministry of Indigenous Relations (the "**MIR**") is undertaking a renewal process for the Government of Alberta’s Policy on Consultation with First Nations on Land and Natural Resource Management, 2013 and the Government of Alberta’s Policy on Consultation with Metis Settlements on Land and Natural Resource Management, 2015. The MIR is currently consulting with affected groups and legislation is expected to be introduced in Fall 2019.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") regulates 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*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licenses, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licenses and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

LIABILITY MANAGEMENT RATING PROGRAM

The provinces of Alberta and British Columbia have each implemented similar liability management programs in respect to upstream oil and gas wells, facilities and pipelines. These programs are designed to assess a licensee’s ability to address its suspension, abandonment, remediation and reclamation liabilities. A licensee whose deemed liabilities exceed its deemed assets within the jurisdiction are required to provide a security deposit.

Alberta

A decision that significantly impacted the status of such programs in 2016 was *Redwater Energy Corporation (Re), 2016 ABQB 278* ("***Redwater***"), where Chief Justice Wittman found that there was an operational conflict of law between the abandonment and reclamation provisions of the provincial OGCA and the ability to disclaim assets under the federal *Bankruptcy and Insolvency Act* ("**BIA**"). Chief Justice Wittman's decision renders the AER's legislated authority under the OGCA unenforceable such that the AER cannot impose abandonment orders against licensees or require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the *BIA*. The AER appealed the decision in the Alberta Court of Appeal, which resulted in the decision being upheld by a count of 2-1. The Supreme Court of Canada began hearing the case on February 15, 2018, and a decision is expected in the summer of 2018.

On June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility-Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("***Bulletin 16***") in an urgent response to *Redwater*. The purpose of *Bulletin 16* is to provide interim rules to govern while the case is appealed and while the Government of Alberta develops appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

1. The AER will consider and process all applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licencee eligibility approval if appropriate in the circumstances.

2. For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the Directors, Officers, and/or Shareholders are substantially the same as when licence eligibility was originally granted.

3. As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

In order to clarify and revise the interim rules in *Bulletin 16*, the AER issued *Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("***Bulletin 21***") on July 8, 2016 and reaffirmed its position that an LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, *Bulletin 21* did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if:

1. The licensee already has an LMR of 2.0 or higher;

2. The acquisition will improve the licensee's LMR to 2.0 or higher; or

3. The licensee is able to satisfy its obligations, notwithstanding an LMR below 2.0, by other means.

Additionally, on December 6, 2017 the AER released Bulletin 2017-21: *New Edition of Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals.* The purpose of the changes is to increase scrutiny to those parties applying for energy licences, by enhancing the information required related to the past history of Officers and Directors of companies. As such, licence eligibility has been altered to encompass three categories: No Eligibility, General Eligibility and Limited Eligibility, with Limited Eligibility being defined as a licencee being able to only hold certain types of licences and approvals, or eligibility is subject to certain terms and conditions. Existing Licencees were required to provide updated information to the AER by completing the Schedule 1 Form of the updated Directive 067 by January 31, 2018, which requests detailed information regarding Officer and Directors and if they have been involved in past insolvency proceedings. An updated form must also be submitted to the AER within 30 days of a material change to the organization. If the licensee fails to do so or where a material change has resulted in an unreasonable risk, the AER may revoke eligibility or restrict eligibility by imposing additional terms and conditions. Material changes include:

- Changes to legal status and corporate structure;

- Addition or removal of a related corporate entity

- Amalgamation, merger or acquisition;
- Change to director, officer, or control persons;
- Appointment of a monitor, receiver, or trustee over the licensee's property;
- Plan of arrangement or any other transaction that results in material change to the operations of the licensee;
- The sale of all or substantially all of the licencees assets; or
- Cancellation of insurance coverage.

The AER has also implemented 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 is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. The IWCP completed its second year on March 31, 2017. Overall, the AER has announced that licensees brought 19% of non-compliant wells in the IWCP into compliance with AER requirements in the second year of the IWCP.

British Columbia

The Commission oversees a similar Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC 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 (i.e., an LMR of below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework. The Commission has announced that it is working to determine how best to manage risks in light of the *Redwater* decision, so changes may be forthcoming.

CLIMATE CHANGE REGULATION

ARC operates in jurisdictions that have regulated or have proposed to regulate GHG and other air pollutants. While some regulations are in effect, others are at various stages of review, discussion and implementation. There is uncertainty around how any future federal legislation will harmonize with provincial regulation, as well as the timing and effects of regulations. Climate change regulation at both the federal and provincial level has the potential to affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry. In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

Federal

The United Nations Framework Convention on Climate Change, held in Paris, France in December 2015, brought together 196 Nations and resulted in the Paris Agreement, which came into effect November 4, 2016. Among other items, the Paris Agreement describes the actions and targets that individual countries will undertake to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and efforts to limit the rise of global temperatures to no more than 1.5° Celsius. The Government of Canada ratified the Paris Agreement on October 5, 2016, and pursuant to the agreement, set forth Nationally Determined Contributions of 30 percent reduction below 2005 levels by 2030.

The Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change on December 9, 2016. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards in 2018. All of the provinces that ARC operates in have carbon pricing systems in place that would meet federal requirements. The federal government will accept comments on the draft legislative proposals to implement the federal carbon pricing system until February 12, 2018.

As part of the Pan-Canadian Framework on Clean Growth and Climate Change, the Government of Canada reaffirmed its commitment to reduce methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025. On May 27, 2017, Environment and Climate Change Canada ("**ECCC**") published draft regulations to reduce emissions of methane from the oil and gas sector. The proposed regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that oil and gas operations use low-emission equipment and processes, by introducing new control measures. The first federal requirements come into force in 2020, with the rest of the requirements coming into force in 2023. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

The Federal GHG reporting threshold has been lowered from 50,000 tonnes to 10,000 tonnes (10 kilotonnes). All facilities that emitted the equivalent of 10 kilotonnes or more of GHGs in carbon dioxide equivalent units (CO2 eq) in 2017 will be required to submit a report. ECCC announced that facilities meeting the new, lowered criteria must submit a report under the Greenhouse Gas Reporting Program to ECCC on or before June 1, 2018. All facilities engaged in carbon capture, transport and geological storage, regardless of their annual GHG emissions, will be required to submit a report covering their activities for 2017 and relevant years for the period 2014 to 2016.

Alberta

Following the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan in November 2015. The Government of Alberta has since introduced new legislation to give effect to the Climate Leadership Plan. The *Climate Leadership Act* (the "**CLA**") came into force on January 1, 2017 enabling a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. The levy is anticipated to increase again in 2021 in line with the federal legislation. All fuel consumption, including gasoline and natural gas, are subject to the levy, with certain exemptions. Corporate directors may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Natural gas produced and consumed on site by conventional oil and gas producers will be exempt from the carbon levy until January 1, 2023.

The passing of the *CLA* is one of the first step towards executing the Climate Leadership Plan and additional legislation is pending. The *Energy Efficiency Alberta Act,* which enables the creation of Energy Efficiency Alberta, a new Crown corporation to support and promote energy efficiency programs and services for homes and businesses has also been enacted.

As part of the Climate Leadership Plan the Alberta government has proposed legislation to meet the methane reduction targets of a 45% reduction in annual methane emissions by 2025. Government consulted a multi stakeholder group, the Methane Regulation Oversight Committee, which advised the AER on proposed methane reduction legislation. The AER has finished the consultation process, and the consultation draft of the regulation is expected in the first quarter 2018. The regulation contemplates increased leak detection and repair and elimination of high bleed instrumentation and is expected to include limits on site vents.

The *Carbon Competitiveness Incentives Regulation* (the "**CCIR**"), which replaces the *Specified Gas Emitters Regulation* ("**SGER**"), came into effect on January 1, 2018. The CCIR specifies an intensity threshold for large emitters. Facilities that emit above the threshold will pay carbon tax on the amount above the threshold, but will be protected from tax on emissions below the threshold (Output Based Allocations or OBA). The CCRI will increase the Corporation's compliance costs for facilities that were previously regulated under SGER.

In order to incentivize the oil and gas industry to develop technologies to reduce emissions intensity, the Government of Alberta also announced innovation funding of $1.4 billion over seven years for innovation projects in five categories. $440 million will be allocated to oilsands.

Currently, the upstream oil and gas industry is exempt from carbon tax until 2023. ARC has no facilities above the 1 Mt CO2e threshold, so there will be no effect on ARC from the recent announcements. The Government of Alberta continues to develop policies for carbon tax to the upstream industry after 2023. These policies may impact ARC if they trend towards stricter thresholds.

British Columbia

British Columbia enacted a carbon tax in February 2008. The tax, which was previously capped at $30 per tonne of CO2 through to 2018 has been increased. The carbon tax will increase from the current $30-dollar per tonne carbon tax by $5 per tonne per year, beginning April 1, 2018 and will likely meet the federally mandated $50 per tonne carbon price by 2022. The Government of British Columbia has also committed to taxing fugitive emissions, which are not currently taxed in any jurisdiction in Canada.

On January 1, 2016, the *Greenhouse Gas Industrial Reporting and Control Act* ("**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects. The *Greenhouse Gas Emission Reporting Regulation*, under the authority of the GGIRCA 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. Companies reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. ARC's gas plants and field operations in British Columbia are subject to provincial reporting regulation.

ACCOUNTABILITY AND TRANSPARENCY

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "**ESTMA**") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

RISK FACTORS

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

Residents of the United States and other non-residents of Canada should have additional regard to the risk factors under the heading *"Additional Risk Factors Applicable to Residents of the United States and Other Non-Residents of Canada"*.

RISKS RELATING TO OUR BUSINESS AND OPERATIONS

Commodity Prices

Our operational and financial results are dependent on the prices received for oil, natural gas and natural gas liquids production. Oil, natural gas and natural gas liquids prices respond to supply and demand and may decrease because of these imbalances. In addition, commodity prices are volatile.

Oil, natural gas, and natural gas liquids 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, natural gas and natural gas liquids, supply disruption, transportation disruption, the price of foreign imports and the availability of alternative fuel sources and changing demand for petroleum products. North America has an abundance of oil and natural gas resources, primarily as a result of advancements in hydraulic fracturing techniques. Natural gas prices are impacted by weather, North American inventory levels, and other factors. Natural gas liquids prices are impacted by the quality of the natural gas liquids, supply/demand balance, and other factors.

Any substantial and extended decline in the price of oil, natural gas, and natural gas liquids would 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, our pace of development and ultimately on our financial condition and therefore on our share price and the dividends to be paid to our Shareholders.

Government Regulation

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. Many of these controls and regulations are subject to exercise of political, governmental and judicial discretion, which may be exercised in a manner that may negatively impact our business. See "Industry Conditions". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition, certain federal legislation such as the Competition Act and the Investment Canada Act could negatively affect our business, financial condition and the market value of our Common Shares or assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Market Access Constraints and Transportation Interruptions

We deliver our products through gathering and pipeline systems (most of which we do not own). The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these systems. This access to market affects regional price differentials, which could result in the inability to realize the full economic potential of our production. Although the transportation systems are expanding, the lack of firm transportation capacity continues to affect the industry and has the potential to limit the ability to produce and to market our production. North America has an integrated network of natural gas pipelines however regional restrictions can arise resulting in curtailments. Any significant change in market factors, infrastructure regulation 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 21 "*Commitments and Contingencies*" in ARC's Audited Consolidated Financial Statements as at and for the year ended December 31, 2017 which section is incorporated in this Annual Information Form by reference and is found on our SEDAR profile at www.sedar.com.

A portion of our production is processed or transported through facilities owned by third parties, which we do not control. From time-to-time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could adversely affect our ability to process our production and to deliver the same for sale.

Public Perception and Influence on Regulatory Regime

Concern over the impact of oil and gas development on the environment and climate change has received considerable attention in the media and recent public commentary, and the social value proposition of resource development is being challenged. Additionally, certain pipeline leaks, and induced seismicity events have gained media, environmental and other stakeholder attention. Future laws and regulation may be impacted by such incidents, which could impede the conduct of our business or make our operations more expensive.

Environmental Regulation

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

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

Climate Change

ARC's exploration and production facilities and other operations and activities emit greenhouse gases which may require it to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of ARC's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See *"Industry Conditions - Climate Change Regulation"*.

Hydraulic Fracturing and the Disposal of Hydraulic Fracturing Fluids

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase our 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 its reserves.

Regulations regarding the disposal of fluids used in the Corporation's operations may increase its costs of compliance or subject it to regulatory penalties or litigation. The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Corporation's costs of compliance.

Global Economic Events

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.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete. The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See *"Industry Conditions - Climate Change Regulation"*. In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes could put the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly or no such carbon regulations.

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See *"Industry Conditions - Royalties and Incentives"*.

Foreign Exchange Rates Fluctuations

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.

Interest Rate Risk

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 new 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.

Exploration, Development and Production Risks

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, 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.

Project Risks

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 and liquids handling facilities, in northeastern British Columbia for the development of our natural gas and crude oil 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:

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

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.

Reliance on Key Personnel

Our success depends in large measure on certain key personnel and our ability to hire and retain our key personnel, and 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, and the safekeeping of our primary workspace and computer systems. Any deterioration of our corporate culture could adversely affect our long-term success.

Dividends

The payment of dividends is at the discretion of the Board of Directors. 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, suspended or discontinued at any 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.

Information Technology Systems

We are dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. We depend on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Cyber-Security

We employ and depend upon information technology systems to conduct our business. These systems have the potential to introduce information security risks, which are growing in both complexity and frequency and could include potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our assets, performance and earnings, as well as on our reputation. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on ARC's business, financial condition and results of operations.

Third Party Credit Risk

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, hedge counterparties 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.

Industry Competition

There are numerous companies in the oil and gas industry, who are competing with us for the acquisition 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, completions 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.

Substantial Capital Requirements and External Sources of Capital, Borrowing and Equity

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

Hedging Activities

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 Reserves 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 who we contract.

Credit Facility Arrangements

We have a $950 million syndicated credit facility with 11 banks, which was undrawn as at December 31, 2017. The current maturity date of the facility is November 8, 2021. 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, 2017, ARC had US$696.0 million and $911.3 million of long-term debt outstanding in the form of Long-term Notes ("**Notes**"). The Notes are repayable over the next 9 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 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, foreign exchange 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*".

Liability Management Programs

Alberta 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 our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. See "*Industry Conditions - Liability Management Rating Program*".

Reserve and Resources Estimates

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 herein and in the GLJ Report are only estimates and the actual production and ultimate reserves and resources from the properties may be greater or less than such 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 contained herein and 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 herein and in the GLJ Report will be reduced in future years to the extent that such activities do not achieve the production performance set forth herein and 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 Contingent Resources contained in the GLJ Report are subject to the definitions, disclaimers, contingencies and warnings set forth in *"Appendix C - Contingent Resource and Prospective Resource Estimates"*. There is no certainty that it will be commercially viable to produce any portion of the resources.

Cost of New Technology

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

Eco-Terrorism Risks

The Corporation's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of Western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Corporation's business and financial results.

Expansion into New Areas

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.

Expiration of Licenses and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we or the holder of the 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.

Failure to Realize 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.

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.

Earnings Volatility

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 "*Future Accounting Policy Changes*" in ARC's audited consolidated financial statements as at and for the year ended December 31, 2017 which section is incorporated in this Annual Information Form by reference and is found on our SEDAR profile at www.sedar.com.

Market Price

The trading price of our Common Shares may be adversely affected by factors related and unrelated to the oil and natural gas industry. The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and gas market. In certain jurisdictions institutions, including government sponsored entities, have determined to decrease their ownership in oil and gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of the common shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the common shares of the Corporation will trade cannot be accurately predicted.

Forward-Looking Information

Forward-Looking Information may not reflect actual outcomes. Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

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

ADDITIONAL RISK FACTORS APPLICABLE TO RESIDENTS OF THE UNITED STATES AND OTHER NON-RESIDENTS OF CANADA

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.

Different 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 and 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 and 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 have included in Appendix C to this the Annual Information Form estimates of Contingent Resources. Contingent Resources are classes of resources and should not be confused with reserves and are subject to the definitions, disclaimers and warnings set forth in Appendix C - Contingent Resource Estimates. The Securities and 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 that reports with the SEC pursuant to the U.S.-Canadian multi-jurisdictional disclosure system.

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.

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.

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 November 6, 2014, as amended on November 23, 2016 and November 1, 2017; between ARC Resources and a syndicate of lenders, and an administrative agent, providing for an extendible revolving credit facility up to $950 million. The maturity date of the facility was extended to November 8, 2021 under the existing terms and revised credit limit on November 23, 2016.
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$20.0 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. The Master Shelf Agreement expired on September 25, 2017.
3. 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 $29 million 6.50% Series E Notes due April 14, 2016 of which US$0 million, US$28 million and $0 million, respectively, are currently outstanding.
4. 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.
5. Note Purchase Agreement dated as of August 23, 2012 between ARC Resources and various purchasers with respect to US$60 million 3.31% Series G Notes due August 23, 2021, US$300 million 3.81% Series H Notes due August 23, 2024 and $40 million 4.49% Series I Notes due August 23, 2024, of which US$48 million, US$300 million and $40 million, respectively, is currently outstanding.

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

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under NI 51-102 by us during, or related to, our most recently completed financial year other than GLJ, our independent qualified reserves evaluator, and PricewaterhouseCoopers LLP, our independent external auditor for the year ended December 31, 2017. 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.

PricewaterhouseCoopers LLP, Chartered Professional Accountants, Calgary, Alberta, have issued their audit opinion dated February 8, 2018, in respect of the Corporation's consolidated financial statements as at December 31, 2017. PricewaterhouseCoopers LLP is independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Professional 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 May 3, 2018. Additional financial information is provided in our consolidated financial statements and accompanying Management's Discussion and Analysis for the year ended December 31, 2017, which have been filed on our SEDAR profile at www.sedar.com. Other additional information relating to us may be found on our SEDAR profile at www.sedar.com.

APPENDIX A

Form 51-101F2

REPORT ON RESERVES DATA AND CONTINGENT RESOURCES 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 and contingent resources data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2017, estimated using forecast prices and costs.
2. The reserves data and contingent resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data and contingent resources data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data and contingent resources data are free of material misstatement. An evaluation also includes assessing whether the reserves data and contingent resources data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of 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 for the year ended December 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - M$)			
Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	12/31/17	Canada	—	5,743,196	—	**5,743,196**

6. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's Board of Directors:

					Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - M$)		
Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (MMboe)	Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	12/31/17	Canada	791.7	—	2,029,407	**2,029,407**

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (MMboe)
Contingent Resources Development Unclarified	GLJ Petroleum Consultants	12/31/17	Canada	730.2
Contingent Resources Development Not Viable	GLJ Petroleum Consultants	12/31/17	Canada	180.1

7. In our opinion, the reserves data, and contingent resources 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 and contingent resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 8, 2018

"Originally Signed by"
Bryan M. Joa, P. Eng.
Vice President

APPENDIX B
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION
FORM 51-101F3

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, and includes, if disclosed in the statement required by item 1 of section 2.1 of NI 51-101, other information such as contingent resources and prospective resources data.

An independent qualified reserves evaluator has evaluated the Company's reserves data and contingent resources 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, and contingent resources data with management and the independent qualified reserves evaluator.

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

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

b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data or, prospective resources data; and

c) the content and filing of this report.

Because the reserves data and contingent resources 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) *"John Dielwart"*
John Dielwart
Director and Member of the Reserves Committee

March 8, 2018

APPENDIX C
CONTINGENT RESOURCE ESTIMATES

ARC engaged GLJ to provide an updated evaluation of, among other things, our Contingent Resources effective December 31, 2017, for our working interest in our northeast British Columbia Montney properties, including lands at Pouce Coupe across the provincial border in Alberta, which Contingent Resources are set forth and described below, all of which will be referred to as “NE BC Montney” for purposes of this Appendix. ARC owns an average 95 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, 2018 forecast pricing. GLJ's January 1, 2018 forecast pricing as set forth under “*Statement of Reserves Data and Other Oil and Gas Information - Forecast Prices and Costs*” in the Annual Information Form to which this Appendix C is attached, is incorporated into this Appendix C by this reference. All applicable resource definitions are provided in the “*Resource Definitions*” section at the end of Appendix C.

Contingent Resources should not be confused with reserves and readers should review the definitions and notes set forth below. Actual tight oil, shale gas, and natural gas liquids resources may be greater than or less than the estimates provided herein. There is uncertainty that it will be commercially viable to produce any portion of the resources.

Summary of Risked Oil and Gas Contingent Resources as of December 31, 2017 - Forecast Prices and Costs

	Contingent Resources (1)(2)(3)							
Resources Project Maturity Sub-Class	Tight Oil		Shale Gas		NGLs		Oil Equivalent	
	Gross (Mbbl)	Net (Mbbl)	Gross (Bcf)	Net (Bcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Contingent (2C)								
Development Pending	32,597	28,510	4,012	3,445	90,354	72,449	791,653	675,052
Development Unclarified	114,514	N/A	3,092	N/A	100,309	N/A	730,218	N/A
Total Economic Contingent Resources	147,110	N/A	7,105	N/A	190,663	N/A	1,521,871	N/A
Development Not Viable	1,243	N/A	697	N/A	62,694	N/A	180,088	N/A

1) All volumes listed in the table are risked, company gross sales volumes.
2) Refer to “Resource Definitions” in this Appendix C for detailed definitions of Contingent Resources, Development Pending, Development Unclarified and Development Not Viable.
3) Net values are only stated for Development Pending. Net values for the remaining sub-classes are N/A as economics were not run, therefore net volumes were not determined.

An estimate of risked net present value (“NPV”) of future net revenues of the development pending contingent resources subclass only is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of ARC proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked NPV of future net revenue will be realized. Subclasses of resources other than development pending are not included in the NPV values and therefore are not reflective of the value of the resource base.

Summary of Risked Net Present Value of Future Net Revenues (Contingent Resources) as of December 31, 2017 - Forecast Prices And Costs

	Risked Net Present Value of Future Net Revenue (1)									
Resources Project Maturity Sub-Class	Before Income Taxes Discounted at % per Year					After Income Taxes Discounted at % per Year				
($ millions)	0	5	10	15	20	0	5	10	15	20
Contingent (2C) Development Pending	12,953	4,675	2,029	993	524	9,455	3,313	1,378	635	308

1) NPV as per GLJ Independent Resources Evaluation as of December 31, 2017 and based on GLJ forecast pricing at January 1, 2018.

Reserves and Resources Reconciliation

Resources will generally move from prospective resources to contingent resources, and then to reserves, and ultimately to production. Approximately 79 MMboe of contingent resources were moved to reserves due to the removal of the chance of development risk. This was due to increased certainty in the resource economics, increased certainty in the development plans, and/or increased certainty in the development timeframe.

Projects for Which Resources Are Being Attributed

The Montney formation in northeast British Columbia and Alberta has been identified as a world-class resource play with the potential for significant volumes of recoverable resources. The area includes dry gas, liquids-rich gas and tight oil development opportunities. It is one of the largest and lowest cost natural gas resource plays in North America. ARC has a significant presence in northeast British Columbia and across the provincial border at Pouce Coupe, with a land position of 771 net sections, located primarily in the most prospective areas of the play.

GLJ was commissioned to conduct an Independent Resources Evaluation for ARC's lands in the NE BC Montney region, including Dawson, Parkland/Tower, Sunrise/Sunset, Sundown, Septimus, Attachie, Red Creek, Mica and Blueberry in northeast British Columbia, and Pouce Coupe just across the provincial border in Alberta (each, an "**Evaluated Area**" and, collectively, "**Evaluated Areas**"). GLJ has prepared best estimates of risked estimates of contingent resources ("CR") associated with the Evaluated Areas. This evaluation is effective December 31, 2017.

The estimated cost to bring on commercial production from the Development Pending CR for all three product types is approximately $7.7 billion (discounted at 10 per cent is approximately $2.4 billion). The expected timeline to bring these resources onto production ranges from two years to seven years depending on the Evaluated Area. ARC's Development Pending CR will represent properties where specific development plans have been made, in areas adjacent to or extending from reserve lands, which have not yet been delineated. These resources are expected to be recovered using the same technology in horizontal drilling and multi-stage fracturing that ARC has already proven to be effective in the Montney in northeast British Columbia.

Chance of Discovery and Development Risk

The Evaluated Areas with CR were risked for the chance of commerciality (CoC), which is defined as follows:

CoC = chance of development (CoDev) × chance of discovery (CoDis)

wherein CoD is for contingent resources is equal to one for all CR.

The chance of development is the estimated probability that, once discovered, a known accumulation will be commercially developed. Five factors have been considered in determining the CoDev as follows:

CoDev = Ps (Economic Factor) × Ps (Technology Factor) × Ps (Development Plan Factor) × Ps (Development Timeframe Factor) × Ps (Other Contingency Factor)

wherein Ps is the probability of success

The five factors were assessed for each of the Evaluated Areas. The following factors were assessed for ARC's CR to be sub-classified and considered as Development Pending CR, Development Unclarified CR or Development Not Viable CR:

- Economic Factor: for Development Pending the associated development projects had robust economics (i.e. strong rate of returns), and as such were assigned a factor of one. The remaining CR sub-classes have factors ranging from 0.75 to 1.0.

- Technology Factor: ARC's NE BC Montney will be developed utilizing established technology, therefore, a technology factor of one is utilized for all resource CR sub-classes.

- Development Plan Factor: detailed development plans and costs were prepared and are in place. This factor ranges from 0.90 to 1.0 for Development Pending CR. Factors less than one account for projects where final pad placement and well locations are less certain. For the remaining CR sub-classes, the Development Plan Factors range from 0.70 to 0.95 based on the level of details provided.

- Development Timeframe Factor: several core areas within the Evaluated Areas have portions of the Petroleum Initially In Place ("**PIIP**") volume developed and producing, with proved and probable reserves assigned. Timing for the CR portions of these projects will depend on the pace of continued development (including allocation of funds), available throughput capacity in existing facilities, or construction of additional facilities. Development Pending projects have been assigned Development Timeframe Factors ranging from 0.90 to 0.95 reflecting the apparent certainty in timing estimates. For the remaining CR sub-classes, the Timeframe Factors assigned range from 0.70 to 0.95.

- Other Contingency Factor: for reserves to be assessed, all contingencies must be eliminated. With respect to contingent resources, this factor captures major contingencies, usually beyond the control of ARC, other than those captured by economic status, technology status, project evaluation scenario status and the development timeframe. The Other Contingency Factor has been assessed as one for all CR sub-classes.

These factors may be inter-related, and care has been taken to ensure that risks are appropriately accounted. The following table summarizes the Chance of Development applied to CR based on the factors assessed.

2017 Contingent Resources Risked CR, Unrisked CR and Chance of Development (1)(2)	**Chance of Development**	**Best Estimate Unrisked**	**Best Estimate Risked**
Shale Gas (Tcf)			
Development Pending CR	86 %	4.6	4.0
Development Unclarified CR	74 %	4.2	3.1
Development Not Viable CR	50 %	1.4	0.7
NGLs (MMbbl)			
Development Pending CR	85 %	105.9	90.4
Development Unclarified CR	72 %	139.8	100.3
Development Not Viable CR	53 %	118.6	62.7
Tight Oil (MMbbl)			
Development Pending CR	92 %	35.5	32.6
Development Unclarified CR	73 %	156.9	114.5
Development Not Viable CR	86 %	1.4	1.2
Total (MMboe)			
Development Pending CR	**86 %**	**915.2**	**791.7**
Development Unclarified CR	**73 %**	**1,000.1**	**730.1**
Development Not Viable CR (3)	**51 %**	**348.1**	**180.1**

1) All volumes listed in the table are company gross sales volumes.
2) Refer to “Resource Definitions” in this Appendix C for detailed definitions of Contingent Resources, Development Pending, Development Unclarified and Development Not Viable.
3) The Chance of Development exceeds 50 per cent for certain NGL and Tight Oil Development Not Viable CR associated with ARC's Tower property because the area is within ARC's development plan and directly offsets the area associated with Development Pending CR estimates. As such, it is more likely than not that these Development Not Viable CR will be commercially developed when compared to Development Not Viable CR that are not included in a development plan or offsetting Development Pending CR. These CR are appropriately classified as Development Not Viable CR because they have a low economic chance of success due to thinner pay that is accessed compared to offsetting Development Pending CR. The estimated volumes associated with these Development Not Viable CR represent less than one per cent of ARC's CR and are not considered material.

Risks and Significant Positive and Negative Factors

Continuous development through multi-year exploration and development programs and significant levels of future capital expenditures are required in order for 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, access to market and the effectiveness of fracturing technology and applications.

Furthermore, it should be understood that CR estimates reflect data as of the effective date. Although only best estimates are reported, it should be understood that there is a significant degree of uncertainty in these estimates. Additional data may justify upward or downward revisions to the estimates, which in turn would impact CR estimates.

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”* in the Annual Information Form to which this Appendix C is attached.

Contingencies

In the NE BC Montney, the primary contingencies that prevent the CR 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, and plans are firmed up, some Contingent Resources are expected to be re-classified to reserves.

Projects have been defined to develop the resources in the NE BC Montney for the Development Pending CR 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 crude oil prices, the results of exploration and development activities of ARC and others in the area and infrastructure capacity constraints.

Resource Definitions

The following are excerpts from the definitions of resources and reserves, contained in Section 5 of the COGE Handbook, which is referenced by the Canadian Securities Administrators in "National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities".

a) **Fundamental Resource Definitions**

Contingent Resources or CR are 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 subclassified based on project maturity and/or characterized by their economic status.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity.

b) **Uncertainty Categories for Resource Estimates**

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

Best Estimate: This is 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 at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

This approach to describing uncertainty may be applied to reserves, contingent resources and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk.

c) **Discovered and Commercial Status and Risks Associated with Resource Estimates**
Discovery Status

Total petroleum initially in place is first subdivided based on the discovery status of a petroleum accumulation. Discovered PIIP, production, reserves, and contingent resources are associated with known accumulations. Recognition as a known accumulation requires that the accumulation be penetrated by a well and have evidence of the existence of petroleum. The COGE Handbook Volume 2, Sections 5.3 and 5.4, provides additional clarification regarding drilling and testing requirements relating to recognition of known accumulations. On the other hand, Prospective resources is undiscovered PIIP which is associated with accumulations yet to be discovered.

Commercial Status

Commercial status differentiates reserves from contingent resources. The following outlines the criteria that should be considered in determining commerciality:

- economic viability of the related development project;
- a reasonable expectation that there will be a market for the expected sales quantities of production required to justify development;
- evidence that the necessary production and transportation facilities are available or can be made available;
- evidence that legal, contractual, environmental, governmental, and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated;
- a reasonable expectation that all required internal and external approvals will be forthcoming. Evidence of this may include items such as signed contracts, budget approvals, and approvals for expenditures, etc.;
- evidence to support a reasonable timetable for development. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a maximum time frame for classification of a project as commercial, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives.

Commercial Risk Applicable to Resource Estimates

Estimates of recoverable quantities are stated in terms of the sales products derived from a development program, assuming commercial development. It must be recognized that reserves and contingent resources involve different risks associated with achieving commerciality. The likelihood that a project will achieve commerciality is referred to as the "chance of commerciality." The chance of commerciality varies in different categories of recoverable resources as follows:

Reserves: To be classified as reserves, estimated recoverable quantities must be associated with a project(s) that has demonstrated commercial viability. Under the fiscal conditions applied in the estimation of reserves, the chance of commerciality is effectively 100 percent.

Contingent Resources: Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For contingent resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development." For contingent resources the chance of commerciality is equal to the chance of development.

d) **Recovery Technology Status**

Established Technology: A recovery method that has been proven to be successful in commercial applications in the subject reservoir and is a prerequisite for assigning reserves.

Technology Under Development: A recovery process that has been determined to be technically viable via field test and is being field tested further to determine its economic viability in the subject reservoir. Contingent resources may be assigned if the project provides information that is sufficient and of a quality to meet the requirements for this resource class.

Experimental Technology: A technology that is being field tested to determine the technical viability of applying a recovery process to unrecoverable discovered PIIP in a subject reservoir. It cannot be used to assign any class of recoverable resources (i.e., reserves and contingent resources).

e) **Economic Status of Resource Estimates**

By definition, reserves are commercially (and hence economically) recoverable. A portion of contingent resources may also be associated with projects that are economically viable but have not yet satisfied all requirements of commerciality. Accordingly, it may be a desirable option to subclassify contingent resources by economic status:

Economic Contingent Resources are those contingent resources that are currently economically recoverable. The CR sub-classes included are Development Pending CR, Development on Hold CR, and Development Unclarified CR.

Sub-Economic Contingent Resources are those contingent resources that are not currently economically recoverable. The CR sub-class included is Development Not Viable.

Where evaluations are incomplete such that it is premature to identify the economic viability of a project, it is acceptable to note that project economic status is "undetermined" (i.e., "contingent resources - economic status undetermined").

In examining economic viability, the same fiscal conditions should be applied as in the estimation of reserves, i.e., specified economic conditions, which are generally accepted as being reasonable (refer to the COGE Handbook Volume 2, Section 5.8).

f) **Project Maturity Sub-Classes for Contingent Resources**

Development Pending: Where resolution of the final conditions for development is being actively pursued (high chance of development).

Development on Hold: Where there is a reasonable chance of development but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

Development Unclarified: When the evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties.

Development Not Viable: Contingent Resource that is not viable in the conditions prevailing at the effective date of the evaluation, and where no further data acquisition or evaluation is currently planned and hence there is a low chance of development.

APPENDIX D

MANDATE OF THE AUDIT COMMITTEE (February 8, 2018)

MANDATE OF THE AUDIT COMMITTEE

Role and Objective

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

- To assist Directors to meet their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation and related matters.
- To provide better communication between Directors and external auditors.
- To ensure the external auditors' independence.
- To 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 management's report on internal control of financial reporting;

   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. review and evaluate annually the external auditors' performance, and periodically, (at least every five years) conduct a comprehensive review of the external auditor;

   d. recommend to the Board appointment of external auditors and the compensation of the external auditors;

   e. 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;

   f. 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; between scheduled meetings, the Chair of the Committee is authorized to approve all audit related services and non-audit services provided by the external auditors for individual engagements with estimated fees of $50,000 and under; and shall report all such approvals to the Committee at its next scheduled meeting;

   g. 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;

   h. review the Annual Report of the Canadian Public Accountability Board ("CPAB") concerning audit quality in Canada and discuss implications for the Corporation;

   i. review any reports issued by CPAB regarding the audit of the Corporation; and

   j. 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 written report 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.