ARC Resources Ltd.
2018 Revised Annual Information Form
March 14, 2019

ARC RESOURCES LTD

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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;

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 the 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 January 25, 2019 evaluating the crude oil, natural gas, natural gas liquids, and sulphur reserves attributable to ARC's properties at December 31, 2018 and evaluating the light oil, shale gas and natural gas liquids resources located in the Montney;

Montney means our lands in northeast British Columbia comprised of the Dawson, Parkland/Tower, Sunrise, Sunset, Sundown, Septimus, Attachie, and Red Creek areas and our lands in northern Alberta in the Pouce Coupe and Ante Creek areas;

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 the stock dividend program;

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

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, 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 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; Impacts of current commodity prices on the Corporation, including with respect to abandonment and reclamation obligations; budget expectations; 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; 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 (“US”) 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 Natural Gas Liquids	
bbl	barrel
bbl/d	barrels per day
Mbbl	thousand barrels
MMbbl	million barrels
NGLs	natural gas liquids
API	Indication of specific gravity of crude oil measured on the American Petroleum Institute ("API") gravity scale
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
GJ	gigajoules
Other	
boe	barrels of oil equivalent
boe per day	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
$M	thousand dollars
$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.**

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
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 2018 of 132,724 boe per day. ARC's business activities include the exploration, development and production of crude oil, natural gas and natural gas liquids in Alberta and British Columbia, Canada. ARC has focused on the acquisition and development of resource-rich properties that provide 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, 2018, ARC had 444 professional, technical and support staff, with 247 employees in the Calgary office and 197 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, 2018.

STRATEGY

ARC's vision is to be a leading energy producer, focused on 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 are substantially 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. The Cardium assets are located 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 efficiencies and low cost operations in a safe and environmentally responsible manner are critical to realizing profitability. ARC is committed, where it makes sense, to owning and operating its own infrastructure.

Financial flexibility and market access – ARC provides returns to Shareholders through a combination of a monthly dividend, currently $0.05 per share, 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 asset dispositions, debt capacity, and when appropriate, equity issuances. ARC chooses to maintain prudent debt levels, targeting its net debt to be between 1.0 and 1.5 times annualized funds from operations(1). ARC maintains a risk management program to reduce the volatility of sales revenues and increase the certainty of funds from operations, and is deliberate in securing takeaway for its products at optimal pricing.

Top talent and strong leadership culture – ARC is committed to the attraction, retention and development of talented and committed people in the energy 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, social and governance reporting practices and open communication with all stakeholders.

(1) Refer to Note 16 "Capital Management" in the financial statements for the year ended December 31, 2018 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, 2018 which are incorporated in this Annual Information Form by reference and 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.

2016

Annual average production of 118,671 boe per day. ARC achieved record full-year average 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 average 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. Finding and development costs for proved plus probable reserves were $4.02 per boe, excluding future development capital. The acquisition of working interests in Pembina Cardium and the 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 base business. In a continued effort to advance ARC's strategy of a concentrated asset base of world-class assets, ARC completed strategic acquisition and disposition activities in 2016. Throughout the year, ARC successfully added to its 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 bbl 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 average 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 of in the fourth quarter of 2016 were effectively replaced with new production primarily 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. Finding and development costs for proved plus probable reserves were $6.41 per boe, excluding future development capital.

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 towards 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 towards 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 resulted in the delineation of a significant portion of ARC's Montney lands, moving inventory into the development stage. Encouraged by 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 drilled 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.

Physical marketing and financial diversification program. ARC's physical marketing diversification and financial risk management activities helped to significantly reduce ARC's exposure to ongoing weakness in western Canadian natural gas prices. Throughout 2017, ARC's natural gas sales portfolio was 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 determined that the costs outweighed the benefits.

2018

Annual average production of 132,724 boe per day. ARC achieved record full-year average production of 132,724 boe per day in 2018, representing an eight per cent increase relative to 2017. The increase in production was predominantly made up of new condensate-rich production flowing through the Dawson Phase III facility, new condensate-rich wells at Attachie West, as well as new production flowing through the Sunrise Phase II gas processing facility expansion. ARC divested approximately 4,700 boe per day of production in 2018, including its Redwater assets in the third quarter of 2018. The annual impact of the non-core dispositions to ARC's full-year average 2018 production was approximately 2,100 boe per day.

Proved plus probable reserves of 879 MMboe identified and 245 per cent of produced reserves replaced. GLJ determined ARC's proved plus probable reserves increased five per cent relative to 2017, totaling 879 MMboe as at December 31, 2018. Approximately 245 per cent of proved plus probable reserves were replaced through capital development activities during the year, and ARC had record proved producing reserve additions of 82 MMboe in 2018. Finding and development costs for proved plus probable reserves were $5.76 per boe, excluding future development capital.

Capital expenditures totaled $679.4 million. During 2018, ARC invested $679.4 million in capital expenditures, before land and net acquisitions and dispositions, approximately 95 per cent of which was directed towards ARC's Montney assets. Capital investment was directed towards several infrastructure projects in 2018, including the Sunrise Phase II gas processing facility expansion, long-term water recycling infrastructure in northeast British Columbia, and a pipeline connecting ARC's Parkland and Dawson assets. ARC also incurred initial investments for the Dawson Phase I & II liquids-handling upgrade, the Dawson Phase IV gas processing and liquids-handling facility, and the Ante Creek 10-36 facility expansion project. ARC drilled 77 wells in 2018 (46 natural gas and liquids-rich natural gas wells, 30 crude oil wells, and one disposal well).

Commissioning of Sunrise Phase II. ARC commissioned the Sunrise Phase II gas processing facility expansion in the third quarter of 2018. Overall, execution of the expansion project was excellent, with the project being completed ahead of schedule, under budget, and with an exceptional safety record. The facility is designed to process 180 MMcf per day of natural gas; an initial 60 MMcf per day of processing capacity was in service in the fourth quarter of 2018, with the remaining balance anticipated to be put in service by June 2019, including 60 MMcf per day of existing production currently being processed through a third-party facility that will be redirected to the Sunrise Phase II facility.

Physical marketing and financial diversification program. ARC maintained its strategy to physically and financially diversify its realized natural gas prices to multiple North American downstream sales points in 2018. ARC's natural gas sales portfolio is physically and financially diversified to multiple downstream markets including US Midwest and Pacific Northwest, Henry Hub, Dawn, AECO, and Station 2 markets. Through ARC’s diversification activities, an incremental $0.72 per Mcf was realized in ARC’s natural gas price in 2018, and ARC’s financial risk management program provided additional cash flow protection with realized cash gains recognized on ARC’s natural gas risk management contracts totaling $0.81 per Mcf. Total realized gains on ARC’s risk management contracts in 2018 were $123.4 million, which represented approximately 15 per cent of annual funds from operations.

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, 2018. 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 January 25, 2019. 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-tax and after-tax basis. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves.

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 cost 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 Crude Oil. ARC's gas reserves and resources in the Montney siltstone are classified as Shale Gas under NI 51-101. ARC's oil reserves and resources in the Montney siltstone are classified as Tight Crude Oil under NI 51-101.

DISCLOSURE OF RESERVES DATA

Company Gross reserves information presented herein is consistent with reserves information disclosed in the February 7, 2019 news release entitled, *"ARC Resources Ltd. Announces 118 MMboe of Total Proved Plus Probable Reserve Additions in 2018, Replacing 245 Per Cent of Production, and Delivers Record Proved Producing Reserve Additions of 82 MMboe*."

Summary of 2018 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 Crude Oil (Mbbl)	NGLs (Mbbl)(1)(2)	Total Oil and NGLs (Mbbl)	Conventional Natural Gas (Bcf)	Shale Gas (Bcf)	Total Gas (Bcf)	Total Oil Equivalent (Mboe)
PROVED									
Developed Producing	31,914	1,328	14,411	24,209	71,863	38.0	996.3	1,034.3	244,246
Developed Non-Producing	546	—	172	1,725	2,443	1.4	55.2	56.6	11,880
Undeveloped	6,198	—	14,302	40,593	61,093	12.1	1,389.4	1,401.5	294,677
TOTAL PROVED	**38,659**	**1,328**	**28,885**	**66,528**	**135,399**	**51.5**	**2,440.9**	**2,492.4**	**550,803**
Probable	10,332	302	18,971	40,572	70,177	19.2	1,528.2	1,547.4	328,072
TOTAL PROVED PLUS PROBABLE	**48,991**	**1,630**	**47,856**	**107,100**	**205,576**	**70.7**	**3,969.1**	**4,039.8**	**878,875**

Company Net Reserves	Light Crude Oil and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Tight Crude Oil (Mbbl)	NGLs (Mbbl)(1)(2)	Total Oil and NGLs (Mbbl)	Conventional Natural Gas (Bcf)	Shale Gas (Bcf)	Total Gas (Bcf)	Total Oil Equivalent (Mboe)
PROVED									
Developed Producing	29,286	1,691	12,435	19,960	63,371	36.0	907.1	943.1	220,560
Developed Non-Producing	490	—	145	1,521	2,157	1.4	52.5	53.9	11,142
Undeveloped	5,682	—	11,240	35,232	52,154	11.5	1,249.1	1,260.6	262,257
TOTAL PROVED	**35,458**	**1,691**	**23,820**	**56,713**	**117,682**	**48.9**	**2,208.7**	**2,257.7**	**493,958**
Probable	8,773	446	15,072	33,267	57,559	18.3	1,349.0	1,367.3	285,439
TOTAL PROVED PLUS PROBABLE	**44,231**	**2,137**	**38,892**	**89,980**	**175,240**	**67.2**	**3,557.7**	**3,624.9**	**779,398**

1) Natural Gas Liquids includes Associated Natural Gas Liquids for both Conventional and Shale/Tight Reservoirs, and includes condensate, propane and butane.
2) Condensate and Pentanes Plus represent 59 per cent of NGLs in the Total Proved and Total Proved Plus Probable categories.

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

Before-Tax Net Present Value [1] ($ millions)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
PROVED					
Developed Producing	3,754	3,031	2,509	2,149	1,890
Developed Non-Producing	205	141	104	81	65
Undeveloped	3,808	2,365	1,537	1,026	691
TOTAL PROVED	**7,767**	**5,537**	**4,150**	**3,255**	**2,645**
Probable	6,392	3,487	2,196	1,515	1,112
TOTAL PROVED PLUS PROBABLE	**14,159**	**9,024**	**6,346**	**4,771**	**3,758**
After-Tax Net Present Value [1][2][3] ($ millions)					
PROVED					
Developed Producing	3,167	2,607	2,181	1,882	1,664
Developed Non-Producing	150	102	74	57	45
Undeveloped	2,767	1,661	1,022	629	374
TOTAL PROVED	**6,084**	**4,369**	**3,277**	**2,567**	**2,083**
Probable	4,688	2,528	1,573	1,073	778
TOTAL PROVED PLUS PROBABLE	**10,772**	**6,897**	**4,850**	**3,640**	**2,861**

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. 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, 2018 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 2018.
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, 2018 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	18,717	2,038	5,838	2,699	374	7,767	1,683	6,084
Proved Plus Probable Reserves	30,656	3,728	8,637	3,671	462	14,159	3,387	10,772

1) Reflects estimated abandonment and reclamation for all wells (both existing and undrilled wells) that have been attributed reserves. 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)	486	$13.70/boe
	Heavy Crude Oil (2)(3)	40	$23.38/boe
	Tight Crude Oil (2)	838	$35.20/boe
	Conventional Natural Gas (4)	4	$0.63/Mcfe
	Shale Gas (4)	2,783	$1.39/Mcfe
	Total	**4,150**	**$8.40/boe**
Proved Plus Probable Reserves	Light Crude Oil and Medium Crude Oil (2)	649	$14.67/boe
	Heavy Crude Oil (2)(3)	50	$23.23/boe
	Tight Crude Oil (2)	1,453	$37.37/boe
	Conventional Natural Gas (4)	5	$0.60/Mcfe
	Shale Gas (4)	4,189	$1.31/Mcfe
	Total	**6,346**	**$8.14/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.

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 prices reference GLJ January 1, 2019 price forecasts and exchange rates as follows:

Summary of GLJ January 1, 2019 Forecast Prices and Inflation Rate Assumptions

	Oil				Natural Gas		Edmonton Liquids Prices				
Forecast	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)	NYMEX Henry Hub(1) Gas Price (US$/MMBtu)	AECO Gas Price (Cdn$/MMBtu)	Propane (Cdn$/bbl)	Butane (Cdn$/bbl)	Pentanes Plus (Cdn$/bbl)	Inflation Rate(2) (%/Year)	Exchange Rate(3) (US$/Cdn $)
2019	56.25	63.33	37.65	58.90	3.00	1.85	25.33	21.45	67.67	2.0	0.750
2020	63.00	75.32	51.21	70.05	3.15	2.29	32.39	37.66	79.22	2.0	0.770
2021	67.00	79.75	59.51	74.16	3.35	2.67	36.68	47.85	83.54	2.0	0.790
2022	70.00	81.48	61.62	75.78	3.50	2.90	39.11	57.04	85.49	2.0	0.810
2023	72.50	83.54	63.82	77.69	3.63	3.14	41.77	58.48	87.80	2.0	0.820
2024	75.00	86.06	66.45	80.04	3.70	3.23	43.03	60.24	90.30	2.0	0.825
2025	77.50	89.09	69.48	82.85	3.77	3.34	44.55	62.36	93.33	2.0	0.825
2026	80.41	92.62	73.01	86.13	3.85	3.41	46.31	64.83	96.86	2.0	0.825
2027	82.02	94.57	74.96	87.95	3.93	3.48	47.28	66.20	98.81	2.0	0.825
2028	83.66	96.56	76.95	89.80	4.00	3.54	48.28	67.59	100.80	2.0	0.825
Thereafter	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	2.0	0.825

1) GLJ assigns a value to ARC's existing physical diversification contracts for natural gas for consuming markets at Dawn, Chicago, Ventura, and Malin based upon GLJ's forecasted differential to NYMEX Henry Hub, contracted volumes, and transportation costs. No incremental value is assigned to potential future contracts which were not in place as of December 31, 2018.
2) Inflation rates for forecasting costs.
3) Exchange rates used to generate the benchmark reference prices in this table.
4) Prices escalate two per cent per year from 2028.

ARC's weighted average prices realized, prior to hedging, for the year ended December 31, 2018, were Cdn$2.37 per Mcf for shale gas and conventional natural gas, Cdn$69.50 per barrel for tight crude oil, light crude oil and medium crude oil, Cdn$37.64 per barrel for heavy crude oil, Cdn$75.56 per barrel for condensate, and Cdn$32.22 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 and 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, 2018, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2018 and as at December 31, 2017 include working interest reserves before royalties payable and without including gross royalties receivable. Key highlights include:

- Negative technical revisions in Tight Crude Oil in the total proved and proved plus probable reserves categories are associated with the reclassification of recovered liquids from oil to condensate in ARC's Attachie property based upon new well classification guidelines in British Columbia. These negative Tight Crude Oil revisions are directly offset by additions of condensate in the NGLs category.
- Further growth in technical revisions to NGLs were observed due to strong performance from the lower Montney horizon across ARC's asset base.
- A minor technical revision to proved plus probable reserves occurred in the Pembina area.
- ARC divested 27 MMboe of proved plus probable reserves in 2018, of which 76 per cent were oil volumes.
- In the category of extensions and improved recovery, ARC added 100 MMboe of proved plus probable reserves, of which approximately 83 per cent resulted from new locations added across the lower Montney in northeast British Columbia and Ante Creek as a result of improved completion techniques. The remaining 17 per cent of additions in this category resulted from improved recovery of existing reserves locations.
- As a result of lower gas price forecasts year over year, ARC observed a minor negative impact on the Economic Factors category.

Reconciliation of Gross Reserves by Principal Product Type

	Light Crude Oil and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Tight Crude Oil (Mbbl)	NGLs (Mbbl)(1)(2)(3)	Total Oil and NGLs (Mbbl)	Conven- tional Natural Gas (Bcf)	Shale Gas (Bcf)	Total Gas (Bcf)	Total Oil Equi- valent 2018 (Mboe)
PROVED									
December 31, 2017	**58,073**	**1,560**	**33,944**	**42,593**	**136,170**	**74.3**	**2,146.6**	**2,220.9**	**506,319**
Extensions and Improved Recovery (4)	—	—	7,144	12,403	19,547	—	299.4	299.4	69,438
Technical Revisions	238	(96)	(7,546)	18,194	10,790	(1.9)	219.0	217.1	46,977
Acquisitions	—	—	—	—	—	—	—	—	—
Dispositions	(16,075)	(12)	—	(1,238)	(17,325)	(15.4)	(2.7)	(18.1)	(20,335)
Economic Factors	—	—	—	(232)	(232)	—	(18.9)	(18.9)	(3,383)
Production	(3,577)	(124)	(4,657)	(5,193)	(13,551)	(5.5)	(202.5)	(208.0)	(48,213)
December 31, 2018	**38,659**	**1,328**	**28,885**	**66,528**	**135,399**	**51.5**	**2,440.9**	**2,492.4**	**550,803**
PROBABLE									
December 31, 2017	**18,976**	**542**	**17,545**	**29,977**	**67,040**	**25.6**	**1,550.8**	**1,576.5**	**329,784**
Extensions and Improved Recovery (4)	—	—	6,229	8,744	14,973	—	96.1	96.1	30,990
Technical Revisions	(4,058)	(233)	(4,803)	2,455	(6,639)	(1.8)	(109.4)	(111.2)	(25,166)
Acquisitions	—	—	—	—	—	—	—	—	—
Dispositions	(4,586)	(7)	—	(597)	(5,191)	(4.7)	(4.5)	(9.1)	(6,712)
Economic Factors	—	—	—	(6)	(6)	—	(4.9)	(4.9)	(824)
Production	—	—	—	—	—	—	—	—	—
December 31, 2018	**10,332**	**302**	**18,971**	**40,572**	**70,177**	**19.2**	**1,528.2**	**1,547.4**	**328,072**
PROVED PLUS PROBABLE									
December 31, 2017	**77,049**	**2,102**	**51,489**	**72,570**	**203,210**	**100.0**	**3,697.4**	**3,797.4**	**836,103**
Extensions and Improved Recovery (4)	—	—	13,373	21,147	34,520	—	395.5	395.5	100,428
Technical Revisions	(3,820)	(329)	(12,349)	20,648	4,151	(3.7)	109.6	106.0	21,811
Acquisitions	—	—	—	—	—	—	—	—	—
Dispositions	(20,661)	(19)	—	(1,835)	(22,515)	(20.1)	(7.1)	(27.2)	(27,047)
Economic Factors	—	—	—	(238)	(238)	—	(23.8)	(23.8)	(4,208)
Production	(3,577)	(124)	(4,657)	(5,193)	(13,551)	(5.5)	(202.5)	(208.0)	(48,213)
December 31, 2018	**48,991**	**1,630**	**47,856**	**107,100**	**205,576**	**70.7**	**3,969.1**	**4,039.8**	**878,875**

1) Natural Gas Liquids includes Associated Natural Gas Liquids for both Conventional and Shale/Tight Reservoirs.
2) Condensate and Pentanes Plus represent 48 per cent of NGLs in the December 31, 2017 opening balance for Proved, Probable, and Proved Plus Probable.
3) Condensate and Pentanes Plus represent 59 per cent of NGLs in the December 31, 2018 closing balance for Proved, Probable, and Proved Plus Probable.
4) 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)
2019	555	634
2020	555	645
2021	598	626
2022	415	540
2023	317	480
Remainder	258	746
Total: Undiscounted	2,699	3,671
Total: Discounted at 10% per Year	2,123	2,746

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 $456 million compared to year-end 2017, to total $3.7 billion at year-end 2018. The change in FDC is mainly attributed to the addition of the Dawson Phase IV gas processing and liquids-handling facility and the Ante Creek 10-36 facility expansion projects, including related drilling activity costs, to ARC's development plan.

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 earnings.

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 Crude 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
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
2018	—	6,198	—	—	2,373	14,302	—	12.1	278.6	1,389.4

	NGLs (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2016	10,507	24,108	83,621	202,656
2017	7,558	20,583	51,249	238,063
2018	12,956	40,593	61,770	294,677

Probable Undeveloped Reserves

	Light Crude Oil and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Tight Crude 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
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
2018	—	3,082	—	—	2,637	13,766	—	6.9	265.8	1,224.5

	NGLs (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2016	16,082	28,291	106,991	234,556
2017	7,968	21,287	47,241	240,188
2018	8,607	32,221	55,537	254,298

As of December 31, 2018, undeveloped reserves represented 53 per cent of total proved reserves and 62 per cent of proved plus probable reserves. Over 90 per cent of the proved plus probable undeveloped reserves are located in our Montney assets of northeast British Columbia and northern Alberta. We have planned a program for the development of a portion of the undeveloped reserves in 2019 and 2020, focusing on the Dawson, Parkland/Tower, Sunrise, Attachie and Ante Creek areas. ARC's 2019 capital program includes infrastructure spending for Dawson Phase IV, Dawson Phase I and II liquids-handling upgrade and the Ante Creek 10-36 facility expansion.

Reserves were assigned adhering to the practices outlined within the COGE Handbook, with uncertainty applied at the individual location level to account for the potential variability in well results. There were 474 total proved, undeveloped locations assigned to be developed over the next five years in the 2018 evaluation which account for 295 MMboe of reserves volumes. Additional to these total proved undeveloped locations are 179 future development locations assigned probable reserves only, an incremental 38 per cent, which extended the timeline to develop these reserves to approximately seven years. These probable locations account for 152 MMboe. The total proved plus probable undeveloped volumes account for 549 MMboe and are all scheduled to produce within the capacity of existing facilities or facilities to which capital has been assigned within the reserves evaluation. Due to these facility capacity limitations, the proved and probable undeveloped reserves are scheduled to be produced beyond a two-year time frame.

The pace of development of the proved and probable undeveloped reserves (both in 2019 and 2020) as well as in years beyond 2020, is influenced by many other 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 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, 2018 for surface leases, wells, facilities and pipelines for properties to which reserves have been attributed (aggregated at a property level)**:**

Abandonment & Reclamation Costs [(1)] **Escalated at 2.0%**	**Undiscounted ($ millions)**	**Discounted at 10%** [(2)] **($ millions)**
Total as at December 31, 2018	872.7	78.7
Anticipated to be paid in 2019	19.5	17.7
Anticipated to be paid in 2020	20.0	16.5
Anticipated to be paid in 2021	20.0	15.0

1) Excludes abandonment and reclamation costs for properties with no attributed reserves.
2) Costs have been discounted in our audited consolidated financial statements for the year ended December 31, 2018 at a liability-specific risk-free rate 2.2 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 property, plant and equipment ("PPE") and exploration and evaluation 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 suspended or 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 ("AER") and the British Columbia Oil and Gas Commission ("BCOGC"). 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, 2018, which are available on our SEDAR profile at www.sedar.com.

As at December 31, 2018, ARC had 3,527 net wells for which we expect to incur abandonment and reclamation costs. In estimating the future net revenues disclosed in this Annual Information Form, the GLJ Report deducted $461.8 million (undiscounted) and $45.9 million (discounted at 10 per cent) for abandonment and reclamation costs for all wells (both existing and undrilled wells) that have been attributed proved and probable reserves.

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 $15.0 million (undiscounted) and $3.4 million (discounted at 10 per cent) not included in these future net revenues for abandonment and reclamation costs related to wells and an additional $37.0 million (undiscounted) and $0.2 million (discounted at 10 per cent) for abandonment and reclamation costs related to facilities and pipelines for our properties with no attributed reserves.

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, 2018, and under the heading "*Asset Retirement Obligations*" in our Management's Discussion and Analysis for the year ended December 31, 2018, which documents are available on our SEDAR profile at www.sedar.com.

CORE OPERATING AREAS

The following is a description of ARC's principal oil and natural gas properties as at December 31, 2018. Information in respect of gross and net acres and well counts are as at December 31, 2018. Due to the fact that ARC has been active at acquiring additional interests in its core operating areas (and divesting of non-core assets), the working interest in gross/net acres and wells as at December 31, 2018 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 ARC.

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. There are no material districts to which reserves have been attributed that are capable of producing but which are not producing at December 31, 2018, 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 94 per cent in approximately 246,995 gross hectares (231,627 net hectares), which includes land holdings of 655 net Montney sections. ARC drilled 62 gross operated wells in 2018 within the region, with an average working interest of 100 per cent. ARC owns and operates approximately 510 MMcf per day of natural gas and 17,500 barrels per day of liquids processing capacity through its facilities in the region, including the Sunrise Phase II gas processing facility, which was commissioned in the third quarter of 2018. The facility was designed to process 180 MMcf per day of natural gas; the initial 60 MMcf per day of processing capacity was in service in the fourth quarter of 2018, with the remaining balance anticipated to be put in service by June 2019.

Alberta

Northern Alberta

ARC has an average working interest of 84 per cent in the area with approximately 191,787 gross hectares (161,357 net hectares), which includes land holdings of 467 net Montney sections. ARC drilled 10 gross operated wells in 2018 within the northern Alberta region, with an average working interest of 100 per cent.

Pembina

ARC has an average working interest of 79 per cent in approximately 81,977 gross hectares (65,106 net hectares). ARC drilled five gross operated Cardium oil wells in 2018, with an average working interest of 100 per cent.

South Central Alberta

ARC has an average working interest of 65 per cent in approximately 13,164 gross hectares (8,602 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, 2018, for our working interest in all of our core Montney properties, including lands at Dawson, Parkland/Tower, Sunrise/Sunset, Septimus, Sundown, Attachie, Red Creek and Mica in northeast British Columbia and lands at Pouce Coupe and Ante Creek 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, 2018.

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	131	130	6	5	445	424	129	116
Alberta	1,498	1,213	758	503	371	79	178	66
Total [3]	1,629	1,343	764	508	816	503	307	182

1) Includes Light Crude Oil and Medium Crude Oil wells, Heavy Crude Oil wells and Tight Crude 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 province our unproved properties as at December 31, 2018.

Undeveloped Hectares

	Gross	Net
British Columbia	167,333	159,317
Alberta	162,706	104,052
Total	330,039	263,369

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 2019. There are no material expiries in our core holdings in 2019.

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 and foreign exchange rates in the normal course of operations. ARC maintains a risk management program including the use of derivative instruments 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, 2018 and in the section under the heading *"Risk Management"* in our Management's Discussion and Analysis for the year ended December 31, 2018, both of which are incorporated by reference into this Annual Information Form and are available on our SEDAR profile at www.sedar.com.

A part of our ongoing strategy is to secure transportation capacity 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 anticipated future growth. Our transportation commitments available 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)	138	132
Crude Oil and NGLs (Mbbl/d)	—	—
Estimated Cost ($ millions)	66	322

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 ARC's proved plus probable reserves based on the GLJ Report, is approximately 55 per cent higher than forecast production from proved reserves used for the purposes of calculating the differences and fees described above. If ARC'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)	99	100
Crude Oil and NGLs (Mbbl/d)	—	—
Estimated Cost ($ millions)	47	239

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, 2018, are set forth in Note 22 *"Commitments and Contingencies"* of our audited consolidated financial statements as at and for the year ended December 31, 2018, 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 $1.8 billion of income tax pools for federal tax purposes as at December 31, 2018. In 2018, ARC recognized current income taxes of $48.4 million. For 2019, ARC expects to recognize current income taxes between two and seven percent of funds from operations; however, this will be dependent on the commodity price environment and capital spending levels. For more information, please see Note 18 *"Income Taxes"* in our audited consolidated financial statements for the year ended December 31, 2018, 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, 2018:

2018 Capital and Land Expenditures

($ millions)	British Columbia	Alberta	Total
Property Acquisition (Disposition) Costs, Net (1)			
Proved Properties	(90.9)	(105.0)	(195.9)
Undeveloped Properties	—	—	—
Exploration Costs (2)	60.1	—	60.1
Development Costs (3)	499.3	105.0	604.3
Capitalized Corporate Costs (4)	—	15.9	15.9
Total	**468.5**	**15.9**	**484.4**

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 ($0.6 million).
3) Represents additions to property, plant, and equipment and includes costs of land acquired ($0.3 million).
4) Includes capitalized overhead and other corporate assets.

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, 2018.

By Well Type	Development Wells (1)		Total (1)(2)	
	Gross	Net	Gross	Net
Crude Oil	32	31.00	32	31.00
Natural Gas	46	46.00	46	46.00
Service Well	1	1.00	1	1.00
Total	**79**	**78.00**	**79**	**78.00**

1) Number of wells based on rig release dates.
2) ARC did not drill any exploration wells, dry holes or stratigraphic test wells for the year ended December 31, 2018.

PRODUCTION ESTIMATES

The following tables set out the GLJ forecast of the volume of production estimated for the year ended December 31, 2019 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 Crude 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	—	—	—	—	—	—	—	—	207,604	199,499	4,880	4,344	39,480	37,594
Sunrise	—	—	—	—	—	—	—	—	201,686	197,276	111	94	33,725	32,973
Other Properties	7,432	7,070	303	648	10,306	7,896	11,745	11,163	151,587	140,683	8,850	7,362	54,113	48,284
Total Proved	**7,432**	**7,070**	**303**	**648**	**10,306**	**7,896**	**11,745**	**11,163**	**560,877**	**537,458**	**13,840**	**11,800**	**127,319**	**118,851**

TOTAL PROBABLE														
	Light Crude Oil & Medium Crude Oil (bbl/d)		**Heavy Crude Oil (bbl/d)**		**Tight Crude 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	—	—	—	—	—	—	—	—	7,301	6,740	173	157	1,390	1,280
Sunrise	—	—	—	—	—	—	—	—	6,763	6,622	3	3	1,130	1,106
Other Properties	308	280	17	42	987	697	954	914	17,447	16,164	1,321	1,125	5,700	4,990
Total Probable	**308**	**280**	**17**	**42**	**987**	**697**	**954**	**914**	**31,510**	**29,526**	**1,497**	**1,284**	**8,220**	**7,377**

TOTAL PROVED PLUS PROBABLE														
	Light Crude Oil & Medium Crude Oil (bbl/d)		**Heavy Crude Oil (bbl/d)**		**Tight Crude 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	—	—	—	—	—	—	—	—	214,905	206,239	5,053	4,501	40,870	38,874
Sunrise	—	—	—	—	—	—	—	—	208,449	203,898	114	96	34,855	34,079
Other Properties	7,740	7,350	320	690	11,294	8,593	12,699	12,077	169,033	156,847	10,171	8,487	59,813	53,274
Total Proved Plus Probable	**7,740**	**7,350**	**320**	**690**	**11,294**	**8,593**	**12,699**	**12,077**	**592,387**	**566,984**	**15,337**	**13,084**	**135,538**	**126,227**

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 2018**				**Year Ended**
	March 31	**June 30**	**September 30**	**December 31**	**2018**
Average Daily Production [1]					
Light and Medium Crude Oil (bbl/d)	12,116	10,872	9,047	7,751	9,926
Heavy Crude Oil (bbl/d)	754	876	915	863	859
Tight Crude Oil (bbl/d)	12,167	13,145	13,905	11,478	12,675
Conventional Natural Gas (MMcf/d)	31.6	21.2	12.8	11.5	14.8
Shale Gas (MMcf/d)	533.3	516.7	561.4	591.8	555.4
NGLs (bbl/d) [2]	11,837	13,340	15,845	15,860	14,236
Condensate (bbl/d)	5,505	6,960	8,158	8,458	7,281
Other NGLs (bbl/d) [3]	6,332	6,380	7,687	7,402	6,955
Total (boe/d)	131,016	127,879	135,410	136,502	132,724
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	69.73	79.57	79.14	42.69	69.25
Heavy Crude Oil ($/bbl)	39.51	47.26	52.29	10.67	37.64
Tight Crude Oil ($/bbl)	70.42	79.26	79.60	46.07	69.69
Conventional Natural Gas ($/Mcf)	3.12	1.87	2.13	2.92	2.60
Shale Gas ($/Mcf)	2.48	1.91	2.15	2.85	2.36
NGLs ($/bbl) [2]	52.80	60.18	61.01	44.12	54.39
Condensate ($/bbl)	77.42	85.10	85.28	57.25	75.56
Other NGLs ($/bbl) [3]	31.39	32.98	35.26	29.12	32.22
Total ($/boe)	28.85	29.59	30.12	24.09	28.12

Production History - continued	Quarter Ended 2018				Year Ended
	March 31	June 30	September 30	December 31	2018
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	6.18	7.69	9.58	4.29	7.00
Heavy Crude Oil ($/bbl)	1.53	1.34	2.36	0.33	1.40
Tight Crude Oil ($/bbl)	11.76	12.45	13.62	7.26	11.42
Conventional Natural Gas ($/Mcf)	(0.35)	(0.44)	(0.15)	(0.20)	(0.30)
Shale Gas ($/Mcf)	0.05	(0.02)	0.01	0.08	0.03
NGLs ($/bbl) (2)	7.03	7.10	6.93	4.36	6.27
Condensate ($/bbl)	9.28	8.98	8.60	4.60	7.64
Other NGLs ($/bbl) (3)	5.08	5.06	5.16	4.10	4.83
Total ($/boe)	2.45	2.55	2.90	1.67	2.39
Operating Expenses (4)(5)					
Light and Medium Crude Oil ($/bbl)	22.98	24.26	27.57	21.30	24.41
Heavy Crude Oil ($/bbl)	11.51	9.50	9.96	11.87	10.67
Tight Crude Oil ($/bbl)	4.30	4.27	4.13	4.07	4.91
Conventional Natural Gas ($/Mcf)	4.04	4.06	4.78	3.64	3.98
Shale Gas ($/Mcf)	0.62	0.68	0.63	0.59	0.63
NGLs ($/bbl) (2)	5.67	6.53	5.53	4.81	5.53
Condensate ($/bbl)	5.35	7.08	5.84	4.90	5.74
Other NGLs ($/bbl) (3)	5.95	5.93	5.20	4.70	5.31
Total ($/boe)	6.31	6.50	6.04	5.04	5.95
Transportation Paid					
Light and Medium Crude Oil ($/bbl)	1.55	1.38	1.54	1.83	1.56
Heavy Crude Oil ($/bbl)	0.54	0.46	0.41	0.43	0.46
Tight Crude Oil ($/bbl)	4.26	3.58	4.14	4.06	4.00
Conventional Natural Gas ($/Mcf)	1.90	2.12	2.73	2.61	2.28
Shale Gas ($/Mcf)	0.31	0.33	0.30	0.29	0.31
NGLs ($/bbl) (2)	5.25	5.12	6.21	6.28	5.78
Condensate ($/bbl)	5.00	6.27	6.94	7.05	6.45
Other NGLs ($/bbl) (3)	5.48	3.87	5.45	5.40	5.08
Total ($/boe)	2.61	2.61	2.75	2.66	2.66
Netback Received (6)					
Light and Medium Crude Oil ($/bbl)	39.02	46.24	40.45	15.27	36.28
Heavy Crude Oil ($/bbl)	25.93	35.96	39.56	(1.96)	25.11
Tight Crude Oil ($/bbl)	50.10	58.96	57.73	30.68	50.08
Conventional Natural Gas ($/Mcf)	(2.47)	(3.87)	(5.23)	(3.13)	(3.36)
Shale Gas ($/Mcf)	1.50	0.92	1.21	1.89	1.39
NGLs ($/bbl) (2)	34.85	41.43	42.34	28.67	36.81
Condensate ($/bbl)	57.79	62.77	63.90	40.70	55.73
Other NGLs ($/bbl) (3)	14.88	18.12	19.45	14.92	17.00
Total ($/boe)	17.48	17.93	18.43	14.72	17.12

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, 2018, 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 80 per cent and 20 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 22 "*Commitments and Contingencies*" in our audited consolidated financial statements for the year ending December 31, 2018, 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 2018, 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 2018 was $2.37 per Mcf before hedging as compared to $2.56 per Mcf before hedging for 2017. This price was achieved with a portfolio mix that on average through the year, before hedging, received AECO index-based pricing for 49 per cent, Station 2 index-based pricing for eight per cent, Midwest index-based pricing for 31 per cent, Pacific Northwest index-based pricing for 10 per cent and Dawn index-based pricing for two 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 through hedging activities.

Crude Oil and Natural Gas Liquids

Our liquids production in 2018 was comprised of approximately 53 per cent light quality crude oil (greater than 35° API), six per cent medium quality crude oil (25° to 35° API), one per cent heavy quality crude oil (less than 25° API) and 40 per cent condensate and natural gas liquids.

During 2018, our average sales prices before hedging were $68.87 per barrel for light and medium crude oil, $48.85 per barrel for heavy crude oil, and $54.39 per barrel for natural gas liquids including free condensate; these prices compare to 2017 prices of $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.

ARC is strategically aligned with its crude oil purchasers which protected us against varying degrees of price volatility in the market.

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 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.arcresources.com/responsibility/sustainability-reports.

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 353,442,447 Common Shares and no preferred shares are outstanding as at December 31, 2018.

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 of Directors 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 1.0 to 1.5 times (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, 2018, 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$637.0 million and $40.0 million of senior notes outstanding. ARC had a net debt balance of $702.7 million outstanding at December 31, 2018, comprised of $909.2 million of long-term debt and a working capital surplus of $206.5 million.

Borrowings under the syndicated credit facility bear interest at bank prime or, at ARC's option, Canadian dollar bankers' acceptances or US 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 October 31, 2018, the credit facility was extended for another year and the pricing terms of the existing facility was revised. The current maturity date of the credit facility is November 8, 2022.

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 three-and-a-half times 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 the book value 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 22-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, 2018, 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*".

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, 2018 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 of Directors, 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 (3) 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 and acts as advisor for Lazard Canada Inc.
Nancy Smith (4) 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 1, 2019.
2) Mr. Dielwart, who is the Chair of the Safety, Reserves and Operational Excellence Committee, retired from the position of Chief Executive Officer ("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 be independent five years after his resignation as CEO of ARC.
3) As of May 3, 2018, Mr. Hearn retired as a director of ARC.
4) 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, had 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 3, 2018 to hold office until the next annual meeting of ARC Resources. The next annual meeting is scheduled to be held on May 1, 2019.

As at December 31, 2018, the Directors and officers of ARC Resources, as a group, beneficially owned, or controlled or directed, directly or indirectly, 6,519,561 Common Shares or approximately 1.84 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, 2018 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.
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 Rundle.
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 Calgary, Alberta, Canada	**Vice President, Engineering and Planning** Ms. Conrad is the Vice President, Engineering and Planning. Prior to February 2014, she was the 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 (1) 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 (2) Calgary, Alberta, Canada	**Corporate Secretary** Mr. Zawalsky is the Managing Partner at Burnet, Duckworth & Palmer LLP (law firm).

1) As of October 31, 2018, Wayne D. Lentz retired from ARC Resources.
2) 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 7, 2019.

Name of Director	Audit	Safety, Reserves & Operational Excellence	Risk	Human Resources & Compensation	Policy & Board Governance	
Independent Directors						
John P. Dielwart (1)		Chair	√			
David R. Collyer		√		Chair		
Fred J. Dyment			√		√	
James C. Houck		√	√			
Harold N. Kvisle						
Kathleen M. O'Neill	Chair				√	
Herbert C. Pinder, Jr.				√	Chair	
William G. Sembo	√			√		
Nancy Smith	√		Chair			

1) Mr. Dielwart, who is the Chair of the Safety, Reserves & Operational Excellence Committees, retired from the position of CEO of ARC Resources effective January 1, 2013 but remains 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 following chart sets out the membership of the committees of the Board of Directors prior to May 3, 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 (2)				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 was the Chair of the Health, Safety and Environment Committee and was a member of the Reserves Committee, prior to the combination of the two committees to form the Safety, Reserves and Operation Excellence 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.
2) Mr. Hearn, who was the Chair of the Human Resources & Compensation Committee and a member of the Policy & Board Governance Committee, retired from the position effective May 3, 2018.

All committees are entirely comprised of independent Directors.

Mr. Stadnyk was promoted to the position of President and Chief Executive Officer 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 management responsibility for the Corporation. Mr. Stadnyk joined ARC in 1997, as the Corporation's first operations employee, and has been President since 2009 and CEO since 2013. Prior to joining ARC, Mr. Stadnyk worked with a major oil and gas company in both domestic and international operations. He holds a Bachelor of Science in Mechanical Engineering from the University of Saskatchewan and is a graduate of the Harvard Business School Advanced Management program. Mr. Stadnyk joined ARC's Board of Directors in 2013. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and currently sits on the Canadian Association of Petroleum Producers Board of Governors and is the current Chair of the British Columbia Executive Policy Group. Mr. Stadnyk sits on the Board of Directors for PrairieSky Royalty Ltd. and STARS (Shock Trauma Air Rescue Society) Ambulance. He is also a board member of the University of Saskatchewan Engineering Advancement Trust and is active with various charitable organizations.

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 of Alberta 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. Prior to being appointed to Senior Vice President and Chief Operating Officer in December 2013, Mr. Anderson held the roles of Senior Vice President of Engineering and Land and Senior Vice President of Operations at ARC. 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 (APEGA) 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 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 Master in Business Administration in Global Energy from the University of Calgary's Haskayne School of Business.

Kristen 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 20 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 Chartered Professional Accountants of Alberta.

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 20 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 M. Conrad, P. Eng.

Ms. Conrad is Vice President, Engineering and Planning of ARC Resources and is responsible for all engineering and strategic planning activities. Ms. Conrad joined ARC in 2011 and has over 20 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 company. 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 company 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).

Lisa A. Olsen, B.A.

Ms. Olsen is Vice President, Human Resources of ARC Resources, and is responsible for human resources, internal communications, office services and records information management while ensuring ARC's unique and high-performance culture endures. Ms. Olsen joined ARC in 2008 and has over 20 years of experience as a human resources practitioner. Prior to joining ARC, Ms. Olsen spent over 10 years leading the human resources functions in both a Canadian oil and gas company as well as for a major international consumer brand. Ms. Olsen has a Bachelor of Communications from Simon Fraser University and a Human Resource Management Certificate from the BC Institute of Technology. Ms. Olsen currently serves as board chair for Enviros and as a member of the Canadian Center for Advanced Leadership at the University of Calgary.

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, 2018, the members of the Audit Committee were Kathleen O'Neill (Chair), William Sembo 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 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 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. She is a current director of the Ontario Teachers' Pension Plan and chairs its Audit and Actuarial Committee. 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.

William G. Sembo

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

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 Bachelor of Arts (Economics) from the University of Alberta, a Masters in Business Administration, 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 individually.

PricewaterhouseCoopers LLP acted as ARC's external auditor for the fiscal years ended December 31, 2018 and 2017. 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		2018		2017
Audit Fees (1)	$	693,000	$	808,740
Audit Related Fees (2)	$	—	$	9,630
Tax Fees (3)	$	—	$	34,101
All Other Fees (4)	$	38,774	$	58,946

1) 2017 audit fees include $125,190 extra billing by ARC's former auditor 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 (the "CPAB") 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 2017 Extractive Sector Transparency Measures Act report, fees related to valuation services of restricted share awards, and fees for non-assurance services related to environmental and sustainability reporting.

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

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.

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 dividend payments were made in the last three completed financial years of ARC:

Dividends	2018	2017	2016
January	$0.05	$0.05	$0.10
February	$0.05	$0.05	$0.05
March	$0.05	$0.05	$0.05
April	$0.05	$0.05	$0.05
May	$0.05	$0.05	$0.05
June	$0.05	$0.05	$0.05
July	$0.05	$0.05	$0.05
August	$0.05	$0.05	$0.05
September	$0.05	$0.05	$0.05
October	$0.05	$0.05	$0.05
November	$0.05	$0.05	$0.05
December	$0.05	$0.05	$0.05
Total	**$0.60**	**$0.60**	**$0.65**

MARKET FOR SECURITIES

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 2018 of the Common Shares on the TSX for the periods indicated (as quoted by Bloomberg):

Toronto Stock Exchange	High	Low	Volume (shares)
January	$15.66	$13.27	28,976,244
February	$13.47	$12.38	32,210,746
March	$14.04	$12.40	26,014,296
April	$15.03	$13.90	27,667,082
May	$14.52	$13.06	25,482,017
June	$13.69	$12.80	20,452,456
July	$15.75	$13.55	20,716,490
August	$15.28	$13.85	21,503,589
September	$14.40	$13.00	35,058,193
October	$14.67	$11.88	37,197,166
November	$12.44	$8.99	51,427,456
December	$9.14	$7.77	44,714,891

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 the manner in which 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 currently 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 enacted by the applicable level of government. Regulated aspects of ARC'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 federal or 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. As a result, macro and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinant of 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

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. 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 pricing of condensates and other natural gas liquids such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, 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. There is no longer a public hearing requirement for the export of natural gas and NGLs. Instead, 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. In addition to NEB approval, all crude oil, natural gas and NGLs licences require the approval of the cabinet of the Canadian federal government ("Cabinet").

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 Cabinet. 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 20 years for quantities not exceeding 30,000 cubic metres 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 criteria prescribed by the NEB and the federal government.

On February 8, 2018, the Government of Canada introduced Bill C-69, draft legislation that, if enacted, will replace the NEB with the Canadian Energy Regulator ("CER"). The CER will take on the NEB's responsibilities with respect to the export of crude oil, natural gas and NGLs from Canada. However, it is not proposed that the legislative regime relating to exports of crude oil, natural gas and NGLs exports from Canada will substantively change under the new regime as currently drafted.

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 US and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete 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 to market on a firm or interruptible basis. Transportation availability is highly variable across different areas and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in western Canada have experienced low commodity pricing relative to other markets in the last several years.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government introduced Bill C-69 to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes will be made in the interim. 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 from provincial and municipal governments, as well as court challenges related to issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of the relevant environmental review processes. Such political and legal opposition creates further uncertainty. In addition, export pipelines from Canada to the US face additional uncertainty as such pipelines require approvals of several levels of government in the US.

In the face of this regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, especially the Midwest US and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of western Canada to reach eastern Canada, the US and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many pipeline projects.

With respect to the current state of the transportation and exportation of crude oil from western Canada to domestic and international markets, the Enbridge Line 3 Expansion from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, experienced a construction permitting setback and is now expected to be in-service in the latter half of 2020.

The proposed Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government entered into an agreement with Kinder Morgan Cochin ULC in May 2018 to purchase the shares and units of the entities that own and operate the Trans Mountain Pipeline system. The shareholders subsequently voted to approve the transaction in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. Following the Court's direction, the Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal decision, including the environmental effects of project-related marine shipping. On February 22, 2019, the NEB delivered an updated report to Cabinet, recommending that Cabinet approve the pipeline expansion, subject to 156 conditions and 16 new recommendations. While Cabinet has three months to consider the NEB's report, it may extend this deadline to accommodate a new round of indigenous consultation, upon completion of which it will decide whether to approve or deny the pipeline expansion.

While it was expected that construction on the Keystone XL Pipeline would commence in the first half of 2019, pre-construction work was halted in late 2018 when a US Federal Court Judge determined the underlying environmental review was inadequate. This decision has been appealed.

Finally, Bill C-48 continues to advance through the federal legislative process. If enacted, Bill C-48 will impose a moratorium on tanker traffic transporting certain crude oil and NGL products from British Columbia's north coast. See "*Environmental Regulation - Federal*" in these Industry Conditions.

The Government of Alberta has also sought to alleviate these transportation constraints by pursuing different transportation modalities and creating new markets. On November 28, 2018, the Government of Alberta announced that Alberta had started negotiations for investment in new rail capacity to address the historically high price differential between Western Canadian crude oil and West Texas Intermediate crude oil. On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 barrels per day of crude oil out of the province. The Alberta Petroleum Marketing Commission will purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. The Government expects the first railcars to be in service by July 2019 and believes this strategy will: (i) narrow the crude oil price gap by up to $4 per barrel; and (ii) provide junior producers with a more affordable option to move their crude oil to market.

On December 11, 2018, the Government of Alberta announced a Request for Expressions of Interest to create new refining capacity or expand existing capacity. The deadline for interested parties to submit Expressions of Interest was February 8, 2019, and an internal governmental committee is currently reviewing such submissions.

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). Repairs or upgrades required on 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. In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project.

CURTAILMENT

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the *Curtailment Rules* (Alberta), the Government of Alberta will, on a monthly basis, direct crude oil producers producing more than 10,000 barrels per day to curtail their production according to a pre-determined formula that apportions production limits proportionately amongst those operators subject to a curtailment order. The first curtailment order took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million barrels per day. A reduction of approximately 8.7 per cent of total daily average crude oil production in Alberta during December 2018. The Government of Alberta indicated that it expected the curtailment rate to gradually drop over the course of 2019. As a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage, the Government of Alberta announced on January 30, 2019, that it would ease the mandatory production curtailment beginning February 1, 2019, increasing the allowable production cap by 75,000 barrels per day to a maximum output of approximately 3.63 million barrels per day. ARC is subject to a curtailment order, however, it has a negligible impact on ARC's production.

THE NORTH AMERICAN FREE TRADE AGREEMENT AND OTHER TRADE AGREEMENTS

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the US and Mexico came into force on January 1, 1994. Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the US and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the US 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.

On November 30, 2018, US President Trump, Prime Minister Trudeau, and outgoing Mexican President Pena Nieto signed an authorization for a new trade deal that will replace NAFTA. The "New NAFTA" is referred to as the United States-Mexico-Canada Agreement ("USMCA"). However, NAFTA remains the North American trade agreement currently in force until the legislative bodies of the three signatory countries ratify the USMCA. Amid political uncertainty in Canada, Mexico, and the US, it is unclear when the end of the NAFTA era will be. As the US 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, the implementation of the final ratified version of the USMCA could have an impact on western Canada's crude oil and natural gas industry at large, including the Corporation's business.

As discussed above, at the end of 2018 the Government of Alberta announced curtailment of Alberta's crude oil and bitumen production for 2019. Curtailment complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen to the other NAFTA signatories. As a result of the proportionality rule, a reduction in Canadian supply reduces the required offering under NAFTA. This may reduce the amount of Canadian crude oil and bitumen being sold at depressed prices. It is not clear whether the USMCA will come into force before the Government of Alberta's curtailment order is repealed automatically on December 31, 2019.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

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 crude oil and natural 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 10 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. On December 30, 2018 the CPTPP came into force among the first six countries to ratify the agreement - Canada, Australia, Japan, Mexico, New Zealand, and Singapore. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the crude oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

LAND TENURE

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

Each of the provinces of Alberta 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 license. The Government of British Columbia expanded its policy of deep rights reversion for leases issued after March 29, 2007 to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of the primary term.

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

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.

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

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 Canadian crude oil and natural gas industry is currently 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 regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural 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, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, current and future changes to environmental legislation, including legislation for air pollution and greenhouse gas ("GHG") emissions, may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal 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 including interprovincial pipelines.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the 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 Cabinet; (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 federal government introduced the *Oil Tanker Moratorium Act* in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, that portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

The AER is the single regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related Acts including the *Oil and Gas Conservation Act* (the "OGCA"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring 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 intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. 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 Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. As a result, several regional plans have been implemented and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

The Ministry of Indigenous Relations (the "MIR") began 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. In 2018, the Ministry updated the Joint Operating Procedures for Consultation on Energy Resource activities (“JOP”) and associated guidelines. The JOPs and Guide were updated to clarify roles and responsibilities, internal procedures and expectation for information sharing. As a result of the update, industry can make applications to the AER (PLA, MSL, LOC) for a Crown Disposition concurrently with application to the Aboriginal Consultation Office.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "OGAA") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the BCOGC has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for crude oil and natural 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 BCOGC to consider these environmental objectives in deciding whether or not to authorize a crude oil or natural 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 licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

The British Columbia Government recently passed *Bill 51 - 2018: Environmental Assessment Act*, which replaces the environmental assessment regime that has been in place since 2002. The Government expects that the updated *Environmental Assessment Act* will enter into force in late 2019. The amendments will subject proposed projects to an enhanced environmental review process similar in substance to the federal environmental assessment process, as well as enhance indigenous engagement in the project approval process with an emphasis on consensus-building.

On July 16, 2018, the BCOGC issued Bulletin 2018-15, outlining critical areas in Blueberry River First Nation (“BRFN”) traditional territory where new surface disturbance will not be permitted or will be restricted and other areas where development activities will be managed. The Interim Measures arose out of the Regional Strategic Environmental Assessment (“RSEA”) which is being done collaboratively with BRFN’s and other Treaty 8 Nations. The Interim Measures provide some additional protections to a small subset of BRFN territory of critical community interest. ARC has no tenure or activities in the area outlined in the bulletin, however access through the designated area, may be required for marketing and sales of future production from ARC’s East Attachie property.

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

The AER administers the licensee Liability Management Rating Program (the "AB LMR Program"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "AB LLR Program"), the Oilfield Waste Liability Program (the "AB OWL Program") and the Large Facility Liability Management Program (the "AB LFP"). At its core, the AER uses the AB LMR Program to aid in determining the ability of licensees to manage the abandonment and reclamation obligations associated with the licensee's assets. If a licensee whose deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licenses. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("LMR"). The AER assesses the LMR of all licensees on a monthly basis and posts the ratings on the AER's public website. Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

Complementing the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "Orphan Fund") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant ("WIP") becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

In '*Orphan Well Association v Grant Thornton Limited*', the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the provincial OGCA, including the AB LLR Program, and the federal *Bankruptcy and Insolvency Act* (the "BIA"). This ruling meant that receivers and trustees of insolvent entities have the right to renounce assets within insolvency proceedings, and was affirmed by a majority of the Alberta Court of Appeal. On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions, holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company's valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in '*Orphan Well Association v Grant Thornton Limited*', the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs pending a final decision from the Supreme Court of Canada. The AER amended its licensing and liability management programs pending a final decision from the Supreme Court of Canada. The AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licence eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. While the Supreme Court of Canada's '*Orphan Well Association v Grant Thornton Limited'* decision alleviates some of the concerns that the AER's rule changes were intended to address, it is unclear how or if the AER will respond.

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 per cent 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 per cent of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81 per cent of licensees operating in the province having met their annual quota. The IWCP completed its third year on March 31, 2018 but the AER has not yet released its third annual report.

As part of its strategy to encourage the decommissioning of inactive or marginal oil and gas infrastructure, the AER announced a voluntary area-based closure ("ABC") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations while enabling participants to meet their liability reduction targets. ARC continues to allocate funds to abandonment and reclamation operations and is in compliance with all requirements. We do not currently participate in the voluntary ABC program, but continue to evaluate the option of doing so in the future.

British Columbia

Similar to Alberta, the BCOGC oversees a 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 BCOGC 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.

In the spring of 2018 the Government of British Columbia passed certain amendments to the OGAA (the "Amendments") which when brought into force, will replace the orphan site reclamation fund tax currently paid by permit holders with a levy paid to the Orphan Site Reclamation Fund ("OSRF"). Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders currently make monthly payments of $0.03 per 1,000 cubic metres of marketable gas produced and $0.06 per cubic meter of petroleum produced. The Amendments will require permit holders to pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the fund. The Amendments permit the BCOGC to impose more than one levy in a given calendar year.

Beginning April 1, 2019, the existing orphan tax will be eliminated and replaced by a new liability levy. This new levy will ensure the Commission has adequate funds to restore all orphan sites in the province in a timely manner. The change is supported in legislation by amendments to section 47 of the Oil and Gas Activities Act authorized by Bill 15 in 2018. The liability levy will be phased in over three years. The 2019/20 fiscal year will see 50 per cent of orphan funding come from the new liability levy, increasing by 25 per cent in each subsequent year. The remaining funding in these years will come from the Commission's operating production levy. By 2021/22, the liability levy will provide 100 per cent of the annual levy required to fund restoration treatment of orphan sites.

CLIMATE CHANGE REGULATION

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulation of the crude oil and natural gas industry in Canada.

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 ARC's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "UNFCCC") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of January 1, 2019, 184 of the 197 parties to the convention have ratified the Paris Agreement. In December 2018, the United Nations annual Conference of the Parties took place in Katowice, Poland. The Conference concluded with the attendees reiterating their commitment to the targets set out in the Paris Agreements and established a transparency framework related to, among other matters, emissions and climate finance reporting.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30 per cent from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "Framework"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10 per tonne, increasing annually until it reaches $50 per tonne in 2022. 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. Seven provinces and territories have introduced carbon-pricing systems in place that would meet federal requirements (Alberta, British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories). The federal carbon-pricing regime will take effect in Saskatchewan, Manitoba, Ontario, New Brunswick in April 2019; it will take effect in the Yukon, and Nunavut in July 2019. Saskatchewan and Ontario have challenged the constitutionality of the federal government's pricing regime; New Brunswick has intervened in Saskatchewan's constitutional challenge. In October 2018, the federal government announced an alternative pricing scheme for large electricity generators designed to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation rates.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "Federal Methane Regulations"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, but will not come into force until January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "CLP"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The *Climate Leadership Act* came into force on January 1, 2017 and enabled a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. While the levy is anticipated to increase again in 2021 in line with the federal legislation, the Government of Alberta has announced it will not proceed with the scheduled 2021 increase unless the expansion to the Trans Mountain Pipeline proceeds. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

The *Carbon Competitiveness Incentives Regulation* (the "CCIR"), which replaces the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50 per cent and 25 per cent for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of one per cent, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal Framework.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45 per cent by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80 per cent below 2007 levels by 2050. Additionally, British Columbia seeks to generate at least 93 per cent of its electricity from clean or renewable sources and build the infrastructure necessary to transmit it. The legislation established no date for this target.

British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at $30 per tonne. However, in its September update to the 2017/2018 Budget, the Government signalled raising the carbon tax to $35 per tonne in April 2018.

On January 1, 2016, the Greenhouse Gas Industrial Reporting and Control Act (the "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.

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan, "CleanBC", which seeks to ensure that British Columbia achieves 75 per cent of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation, construction, and waste sectors of the British Columbia economy. Key initiatives include: i) increasing the generation of electricity from clean and renewable energy sources; ii) imposing a 15 per cent renewable content requirement in natural gas by 2030; iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20 per cent by 2030; iv) investing in the electrification of crude oil and natural gas production; v) reducing 45 per cent of methane emissions associated with natural gas production; and vi) incentivizing the adoption of zero-emissions vehicles. On January 16, 2019, the BCOGC announced a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules will come into effect on January 1, 2020.

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 Cdn$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

Weakness in the Oil and Natural Gas Industry

Weakness and volatility in the market conditions for the oil and natural gas industry may affect the value of the Corporation's reserves, restrict its cash flow and its ability to access capital to fund the development of it's properties

Recent market events and conditions, including excess global oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("OPEC"), slowing growth in China and emerging economies, market volatility and disruptions in Asia, weakening global relationships, isolationist trade policies, increased US shale production, sovereign debt levels, and political upheavals in various countries have caused significant weakness and volatility in commodity prices. See "*Risk Factors - Political Uncertainty*". These events and conditions have caused a decrease in the valuation of oil and natural gas companies. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Risk Factors - Royalties and Incentives*", *"Risk Factors - Regulatory Authorities and Environmental Regulation*" and "*Risk Factors - Climate Change Regulation*". In addition, the inability to get the necessary approvals to build pipelines, liquified natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in western Canada has led to additional downward price pressure on oil and natural gas produced in western Canada and uncertainty and reduced confidence in the oil and natural gas industry in western Canada. See "*Industry Conditions - Transportation Constraints and Market Access*".

Lower commodity prices may also affect the volume and value of ARC's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict ARC's cash flow resulting in less funds from operations being available to fund ARC's capital expenditure budget and dividend. Consequently, ARC may not be able to replace its production with additional reserves and both ARC's production and reserves could be reduced on a year-over-year basis. See "*Risk Factors - Reserves Estimates*". In addition to possibly resulting in a decrease in the value of ARC's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of ARC's infrastructure and facilities, all of which could also have the effect of requiring a write-down of the carrying value of ARC's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, ARC may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and under highly dilutive terms. See "*Risk Factors - Additional Funding Requirements*".

Exploration, Development and Production Risks

The Corporation's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas

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

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

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

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

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

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

Political Uncertainty

Changes in governing political parties and/or government policies may adversely affect the Corporation

In the last several years, the US and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 US presidential election, the American administration has begun taking steps to implement certain of its promises made during the campaign. The administration has withdrawn the US from the Trans-Pacific Partnership and Congress has passed tax reform, which, among other things, significantly reduces US corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the US and Mexico signed the USMCA which will replace NAFTA once ratified by the three signatory countries. See "*Industry Conditions - The North American Trade Agreement and Other Trade Agreements*". The US administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the US administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current US administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation.

In addition to the political disruption in the US, the citizens of the United Kingdom voted to withdraw from the European Union and the Government of the United Kingdom has taken steps to implement such withdrawal. The terms of the United Kingdom's exit from the European Union and whether it will occur at all remains to be determined. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on ARC's ability to market its products internationally, increase costs for goods and services required for ARC's operations, reduce access to skilled labour and negatively impact ARC's business, operations, financial conditions and the market value of the Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy such as the potential impact of the recent change of government in British Columbia and announcements and actions by the government of British Columbia that may impact the completion of the Trans-Mountain Pipeline project, liquified natural gas facilities and other infrastructure projects.

Project Risks

The success of the Corporation's operations may be negatively impacted by factors outside of its control resulting in operational delays and cost overruns

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, 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;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, ARC could be unable to execute projects on time, on budget, or at all.

Gathering and Processing Facilities, Pipeline Systems and Rail

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on the Corporation's ability to produce and sell its oil and natural gas

ARC delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that ARC can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The ongoing lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in ARC's inability to realize the full economic potential of its production, or in a reduction of the price offered for ARC's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. See "*Industry Conditions - Transportation Constraints and Market Access* ". In addition, the pro-rationing of capacity on inter provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect ARC's production, operations and financial results. As a result, producers are increasingly turning to rail lines as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm ARC's business and, in turn, ARC's financial condition, operations and cash flows. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has introduced Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing for receipt of approvals of major projects remains unclear.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the US National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids, which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of rail transportation to alleviate pipeline constraints and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the US will be monitored to ensure they are compliant with Protective Direction No. 38.

A portion of ARC's production may, from time-to-time, be processed through facilities owned by third parties and over which ARC does not have control. From time-to-time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on ARC's ability to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment, which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Competition

The Corporation competes with other oil and natural gas companies, some of which have greater financial and operational resources

ARC competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas. ARC's competitors include oil and natural gas companies that have greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than ARC. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage.

Cost of New Technologies

The Corporation's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete

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

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Corporation's financial condition, results of operations and cash flow

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. ARC cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the ARC's business, financial condition, results of operations and cash flow by decreasing ARC's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Regulatory

Modification to current, or implementation of additional, regulations may reduce the demand for oil and natural gas and/or increase the Corporation's costs and/or delay planned operations

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing, transportation and infrastructure). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties, the exportation of oil and natural gas and infrastructure projects. Amendments to these controls and regulations may occur, from time-to-time, in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase ARC's costs, either of which may have a material adverse effect on ARC's business, financial condition, results of operations and prospects. Further, the ongoing third-party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and natural gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact ARC's operations, which may affect ARC's profitability. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation - Climate Change Regulations*". Also, in response to widening pricing differentials, the Government of Alberta implemented production curtailment. See "*Industry Conditions - Curtailment"* and "*Risk Factors - Liability Management"*.

In order to conduct oil and natural gas operations, ARC will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that ARC will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect ARC's business, financial condition and the market value of its common shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation - Liability Management Rating Programs*".

Royalty Regimes

Changes to royalty regimes may negatively impact the Corporation's cash flows

There can be no assurance that the governments in the jurisdictions in which ARC has assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of ARC's projects. An increase in royalties would reduce ARC's earnings and could make future capital investments, or the Corporation's 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*".

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Corporation's financial position

Hydraulic fracturing involves the injection of water, sand and 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 ARC's costs of compliance and doing business, as well as delay the development of oil and natural gas resources from tight siltstone or 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 ARC is ultimately able to produce from its reserves.

Due to seismic activity reported in the Fox Creek area of Alberta, the AER announced in February 2015, seismic monitoring and reporting requirements for hydraulic fracturing operations in the Duvernay zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for induced seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events, and the suspension of operations if a seismic event above a particular threshold occurs. These requirements will remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary. ARC does not have any hydraulic fracturing operations in the Duvernay zone in Alberta.

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how British Columbia's regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. Despite a timeline to fulfill its mandate by December 31, 2018, the panel's findings are not yet publically available. Therefore, it is unclear how the panel's recommendations will influence the regulatory regime currently in place in British Columbia. The implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect ARC's business operation, financial condition, results of operations and prospects.

Due to seismic activity recorded in the Kiskatinaw Seismic Monitoring and Mitigation ("Kiskatinaw") area, in May 2018, the BCOGC issued special notification and monitoring requirements for hydraulic fracturing operators in the Kiskatinaw area. These requirements include, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations, pre-operation notification to both residents and the BCOGC, and the suspension of operations if a seismic event above a 3.0 magnitude (in Richter magnitude scale) occurs. In November 2018, seismic activity near Fort St. John in the Kiskatinaw area resulted in the suspension of several companies' operations, in a defined region of the Kiskatinaw area for 30 days. The BCOGC continues to monitor seismic events across the province and may implement similar requirements as part of hydraulic fracturing operation regulations, if necessary.

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for water storage reservoirs, referred to as dams, which are constructed to provide water required for hydraulic fracturing operations. Under the *Water Sustainability Act*, the storage of water from a groundwater source or a stream requires authorization. In addition, structures constructed for water storage above natural grade elevation behind a berm or barrier (i.e., “live storage”) are dams and require compliance under the Dam Safety Regulations and require compliance with the construction and operations standards specified by the Ministry of Forests, Lands and Natural Resources Operations. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the required regulatory authorization. While the BCOGC has issued compliance orders with respect to individual dams, it is uncertain how, and to what extent the relevant industry regulators will respond to this issue. All water storage reservoirs constructed by ARC meet the necessary regulatory approvals and are in full compliance with the above mentioned regulations. Additionally, the Corporation has taken extra measures towards ensuring all third-party water storage reservoirs used to support ARC’s hydraulic fracturing operations are in compliance.

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Corporation's financial and operational resources

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 natural 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 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 ARC's business, financial condition, results of operations and prospects.

Operational Dependence

The Corporation is subject to risk as it pertains to other parties operating assets it has an interest in

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

In addition, due to volatile commodity prices, many companies, including companies that may operate some of the assets in which ARC has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which ARC has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, ARC may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, ARC potentially becoming subject to additional liabilities relating to such assets and ARC having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on ARC’s financial and operational results. See "*Industry Conditions - Liability Management Rating Program*".

Waterflood

Regulatory water use restrictions and/or limited access to water or other fluids may impact the Corporation's production volumes from its waterflood assets

ARC undertakes or intends to undertake certain waterflooding programs, which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities ARC needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to maintain or increase the pressure in the reservoir. There is no certainty that ARC will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If ARC is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that ARC is ultimately able to produce from its reservoirs. In addition, ARC may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Corporation's results of operations.

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 - Regulatory Authorities and Environmental Regulation - 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 an adverse effect on ARC's profitability and financial condition. Further, the imposition of carbon taxes puts ARC at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Corporation's ability to acquire properties or require a substantial cash deposit with the regulator

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 is unable to satisfy its regulatory obligations. These programs 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 generally required. Changes to the required ratio of ARC's deemed assets to deemed liabilities, or other changes to the requirements of liability management programs, may result in significant increases to ARC's compliance obligations. In addition, the liability management regime may prevent or interfere with ARC's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The impact and consequences of the Supreme Court of Canada's decision in the "*Orphan Well Association v Grant Thornton Limited*" on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings will no doubt evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation - Liability Management Rating Programs*".

Climate Change

Compliance with greenhouse gas emissions regulations may result in increased operational costs to the Corporation

ARC's exploration and production facilities and other operations and activities emit GHG which may require the Corporation to comply with greenhouse gas emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to-date by the Government of Canada to reduce GHG emissions is the planned implementation of a nation-wide price on carbon emissions. The federal carbon levy goes into effect on April 1, 2019 and will affect provinces which have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing, namely Ontario, Manitoba, Saskatchewan and New Brunswick. The federal carbon levy will be at an initial rate of $20 per tonne. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The implementation of the federal carbon levy is currently subject to constitutional challenges submitted by the Provinces of Saskatchewan and Ontario, which are supported by the province of New Brunswick. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on ARC'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.

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. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify a class action against the Government of Canada for climate related matters. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for climate-related harms. See "*Risk Factors - Non-Governmental Organizations and Eco-Terrorism Risks*" and "*Risk Factors - Reputational Risk Associated with the Corporation's Operations*"**.**

Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the affect of increasing ARC's operating expenses and in the long term reducing the demand for oil and natural gas production, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or asset impairments. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation - Climate Change Regulation*".

In addition, there has been public discussion that climate change may be associated with extreme weather conditions and increased volatility in seasonal temperatures. Extreme weather could interfere with ARC's production and increase the Corporation's costs. At this time, ARC is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting its operations.

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Corporation's financial condition

World oil and natural gas prices are quoted in US dollars. The Canadian/US dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the US dollar will negatively affect ARC's production revenues. Accordingly, exchange rates between Canada and the US could affect the future value of ARC's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the US dollar may positively affect the price ARC receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for ARC's operations, which may have a negative impact on the ARC's financial results**.**

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

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

Capital Requirements

The Corporation's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations and acquire and develop reserves

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

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

Further, if ARC's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including ARC, to access additional financing and/or the cost thereof. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. ARC may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of ARC to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation's ability to engage in acquisition and/or disposition activity may be impacted by government regulations which may adversely affect the Corporation

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. 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.

Additional Funding Requirements

The Corporation may require additional financing from time-to-time to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility

ARC's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and, from time-to-time, ARC may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause ARC to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Corporation may, from time-to-time, have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access, or the cost of, additional financing.

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

Credit Facility Arrangements

Failing to comply with covenants under the Corporation's credit facility could result in restricted access to capital or being required to repay all amounts owing thereunder

ARC is required to comply with covenants under its credit facility and note agreements which may, in certain cases, include certain financial ratio tests, which, from time-to-time, either affect the availability, or price, of additional funding and in the event that ARC does not comply with these covenants, ARC's access to capital could be restricted or repayment could be required. Events beyond ARC's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under ARC's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. The acceleration of ARC's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, ARC's credit facility may impose operating and financial restrictions on ARC that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to ARC's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others**.**

ARC's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors to periodically determine ARC's credit facility size. Commodity prices continue to be depressed and have fallen since 2014, and while prices have recently increased they remain volatile as a result of various factors including limited egress options for western Canadian oil and natural gas producers, actions taken to limit OPEC and non-OPEC production and increasing production by United States shale producers. Depressed commodity prices could reduce ARC's borrowing ability, reducing the funds available to ARC under the credit facility. This could result in the requirement to repay a portion, or all, of ARC's indebtedness.

The impact of the Supreme Court of Canada's decision in the '*Orphan Well Association v Grant Thornton Limited*' case on lending practices in the oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has not yet been determined but could affect lending practices as secured creditors will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation - Liability Management Rating Programs*".

If ARC's lenders require repayment of all or a portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant, there is no certainty that ARC would be in a position to make such repayment. Even if ARC is able to obtain new financing in order to make any required repayment under its credit facilities, it may not be on commercially reasonable terms, or terms that are acceptable to the Corporation. If ARC is unable to repay amounts owing under credit facilities, the lenders under its credit facilities could proceed to foreclose.

Issuance of Debt

Increased debt levels may impair the Corporation's ability to borrow additional capital on a timely basis to fund opportunities as they arise

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

Hedging

Hedging activities expose the Corporation to the risk of financial loss and counter-party risk

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

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

Similarly, from time-to-time, ARC may enter into agreements to fix the exchange rate of Canadian to US dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, ARC will not benefit from the fluctuating exchange rate.

Availability and Cost of Material and Equipment

Restrictions on the availability and cost of materials and equipment may impede the Corporation's exploration, development and operating activities

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials, services and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment could become limited, if a sudden increase in market activity and demand is observed. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the ARC's exploration, development and operating activities.

The Corporation Requires a Skilled Workforce

An inability to recruit and retain a skilled workforce may negatively impact the Corporation

The operations and management of ARC require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement ARC's business plans. ARC competes with other companies in the oil and natural gas industry, as well as other industries, for this skilled workforce. A decline in market conditions has led increasing numbers of skilled personnel to seek employment in other industries. In addition, certain of ARC’s current employees are senior and have institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If ARC is unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, ARC could be negatively impacted. In addition, ARC could experience increased costs to retain and recruit these professionals.

Title to and Right to Produce from Assets

Defects in the title or rights to produce the Corporation's properties may result in a financial loss

ARC's actual title to and interest in its properties, and its right to produce and sell the oil and natural gas therefrom, may vary from the Corporation's records. In addition, there may be valid legal challenges or legislative changes that affect ARC's title to and right to produce from its oil and natural gas properties, which could impair the Corporation's activities and result in a reduction of the revenue received by ARC.

If a defect exists in the chain of title or in ARC’s right to produce, or a legal challenge or legislative change arises, it is possible that ARC may lose all, or a portion of, the properties to which the title defect relates and/or its right to produce from such properties. This may have a material adverse effect on ARC's business, financial condition, results of operations and prospects.

Reserves and Resources Estimates

The Corporation's estimated reserves and resources are based on numerous factors and assumptions which may prove incorrect and which may affect the Corporation

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

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

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

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often 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.

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

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

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 Estimates*". There is no certainty that it will be commercially viable to produce any portion of the resources.

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Corporation

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

Geopolitical Risks

Global political events may adversely affect commodity prices which in turn affect the Corporation's cash flow

Political changes in North America and political instability in the Middle East and elsewhere may cause disruptions in the supply of oil that affects the marketability and price of oil and natural gas acquired or discovered by ARC. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or parties in power, may have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of ARC's net production revenue.

Non-governmental Organizations and Eco-terrorism Risks

The Corporation's properties may be subject to action by non-governmental organizations or terrorist attack

The oil and natural gas exploration, development and operating activities conducted by ARC may, at times, be subject to public opposition. Such public opposition could expose ARC to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that ARC will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Corporation to incur significant and unanticipated capital and operating expenditures.

In addition, ARC'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 a terrorist attack it may have a material adverse effect on ARC's business, financial condition, results of operations, and prospects. ARC does not have insurance to protect against the risk from terrorism.

Reputational Risk Associated with the Corporation's Operations

The Corporation relies on its reputation to continue its operations and to attract and retain investors and employees

ARC’s business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Corporation or as a result of any negative sentiment toward, or in respect of, the Corporation's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which ARC operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. ARC's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Corporation has no control. Similarly, ARC's reputation could be impacted by negative publicity related to loss of life, injury or damage to property and environmental damage caused by ARC’s operations. In addition, if ARC develops a reputation of having an unsafe work site it may impact the ability of the Corporation to attract and retain the necessary skilled employees and consultants to operate its business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and fossil fuel companies may impact the ARC's reputation. See "*Risk Factors - Climate Change*".

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard ARC's reputation. Damage to ARC's reputation could result in negative investor sentiment towards the Corporation, which may result in limiting ARC's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Corporation's securities.

Changing Investor Sentiment

Changing investor sentiment towards the oil and natural gas industry may impact the Corporation's access to, and cost of, capital

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during transportation and indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they are no longer willing to fund or invest in oil and natural gas properties or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board of Directors, Management and employees of ARC. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in ARC, or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, ARC, may result in limiting ARC's access to capital, increasing the cost of capital, and decreasing the price and liquidity of ARC's securities even if ARC's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of ARC's assets which may result in an impairment change.

Dilution

The Corporation may issue additional Common Shares, diluting current Shareholders

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

Expiration of Licenses and Leases

The Corporation, or its working interest partners, may fail to meet the requirements of a licence or lease, causing its termination or expiry

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

Dividends

The payment of cash dividends could vary

The amount of future cash dividends paid by ARC, if any, is subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time-to-time, including, among other things, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Corporation, the dividend policy of ARC from time-to-time and, as a result, future cash dividends could be reduced or suspended entirely.

The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by ARC and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by ARC to finance capital expenditures using funds from operations.

To the extent that external sources of capital, including in exchange for the issuance of additional Common Shares, become limited or unavailable, the ability of ARC to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that ARC is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Litigation

The Corporation may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Corporation and its reputation

In the normal course of ARC's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings, and legal actions. Potential litigation may develop in relation to personal injuries (including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages, and contract disputes). The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to ARC and could have a material adverse effect on ARC's assets, liabilities, business, financial condition, and results of operations. Even if ARC prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of Management and key personnel from business operations, which could have an adverse affect on ARC's financial condition.

Indigenous Claims

Indigenous claims may affect the Corporation

Indigenous peoples have claimed aboriginal title and rights in portions of western Canada. ARC 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 ARC'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 ARC's business and financial results.

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Corporation's competitive advantage or put it at risk of litigation

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

Income Taxes

Taxation authorities may reassess the Corporation's tax returns

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

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

Seasonality and Extreme Weather Conditions

Oil and natural gas operations are subject to seasonal and extreme weather conditions and the Corporation may experience significant operational delays as a result

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of ARC's production if unable to access. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of muskeg. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict ARC's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

Third-party Credit Risk

The Corporation is exposed to credit risk of third-party operators or partners of properties in which it has an interest

ARC may be exposed to third-party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, ARC may be exposed to third-party credit risk from operators of properties in which ARC has a working or royalty interest. In the event such entities fail to meet their contractual obligations to ARC, such failures may have an adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry, generally, and of ARC's joint venture partners may affect a joint venture partner's willingness to participate in ARC's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in ARC being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect ARC’s financial and operational results.

Reliance on Key Personnel

Loss of key personnel would negatively impact the Corporation's operations

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

Information Technology Systems and Cyber-security

A disruption of information technology services of a cyber-security breach may adversely affect the Corporation

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.

We employ and depend upon information technology systems to conduct our business. These systems are subject to a variety of 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. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years, primarily due to their high rate of success. A successful cyber phishing attack could result in a loss or theft of our financial resources or critical data and information, or could result in a loss of control of our technological infrastructure or financial resources. Our employees are often recipients of such cyber phishing attacks through campaigns targeting the upstream oil and gas sector or large corporations.

We maintain policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conduct annual cyber-security assessments. We also employ encryption protection of all computers and portable electronic devices. Despite our efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage our information technology infrastructure. We apply technical and process controls in line with industry-accepted standards and best practices to protect our information, assets and systems, including a written incident response plan for responding to a cyber-security incident. However, due to the variety, sophistication and frequency of change in technology, these controls may not adequately prevent cyber-security breaches. 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 our business, financial condition, and results of operations.

Social Media

The Corporation faces compliance and supervisory challenges in respect of the use of social media as a means of communicating with clients and the general public.

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into our systems and obtain confidential information. We provide employees with social media guidelines that align with our Business Code of Conduct and Ethics Policy. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that we may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

Expansion into New Activities

Expanding the Corporation's business exposes it to new risks and uncertainties

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

Access to Our Offices and Properties

Employees of the Corporation require access to our offices

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.

Market Price

The trading price of the 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 ARC's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities and equities has increased due, in part, to the implementation of computerized trading and the decrease of actively managed portfolios. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural 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 ARC could be subject to significant fluctuations in response to variations in ARC’s operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares of ARC will trade cannot be accurately predicted.

Earnings Volatility

Earnings of the Corporation may fluctuate in each reporting period

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 reversals 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, 2018 which section is incorporated in this Annual Information Form by reference and is found on our SEDAR profile at www.sedar.com.

Forward-looking Information

Forward-looking information may prove inaccurate

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

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, November 1, 2017 and October 31, 2018; 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, 2022 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$10 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 $29 million 6.50% Series E Notes due April 14, 2016 of which US$nil, US$21 million and $nil 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$120 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$36 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, 2018. 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 7, 2019, in respect of the Corporation's consolidated financial statements as at December 31, 2018. 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 1, 2019. Additional financial information is provided in our consolidated financial statements and accompanying Management's Discussion and Analysis for the year ended December 31, 2018, 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
REPORT ON RESERVES DATA AND CONTINGENT RESOURCES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR
Form 51-101F2

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, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, 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, 2018, 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 per cent, included in the reserves data of the Company evaluated for the year ended December 31, 2018, 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	12/31/18	Canada	—	6,345,814	—	**6,345,814**

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 per cent, 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	12/31/18	Canada	1,189.9	—	4,016,727	**4,016,727**

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	12/31/18	Canada	644.3
Contingent Resources Development Not Viable	GLJ Petroleum Consultants	12/31/18	Canada	135.4

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 judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, January 25, 2019

"Originally Signed by"
Chad P. Lemke, 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 Safety, Reserves and Operational Excellence 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 Safety, Reserves and Operational Excellence 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 Safety, Reserves and Operational Excellence 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) *"John Dielwart"*
John Dielwart
Director and Chair of the Safety, Reserves and Operational Excellence Committee

(signed) "David Collyer"
David Collyer
Director and Member of the Safety, Reserves and Operational Excellence Committee

March 7, 2019

APPENDIX C

CONTINGENT RESOURCE ESTIMATES

ARC engaged GLJ to provide an updated evaluation of, among other things, our Contingent Resources effective December 31, 2018, for our working interest in all of our core Montney properties, including lands at Dawson, Parkland/Tower, Sunrise/Sunset, Septimus, Sundown, Attachie, Red Creek and Mica in northeast British Columbia and lands at Pouce Coupe and Ante Creek in Alberta, which Contingent Resources are set forth and described below. ARC owns an average 98 per cent working interest in our core Montney properties listed above. 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, 2019 forecast pricing. GLJ's January 1, 2019 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 crude 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, 2018 - Forecast Prices and Costs

	Contingent Resources (1)(2)(3)							
Resources Project Maturity Sub-Class	Tight Crude 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	46,855	38,574	5,330	5,035	254,615	207,013	1,189,882	1,084,741
Development Unclarified	17,237	N/A	2,818	N/A	157,392	N/A	644,324	N/A
Total Economic Contingent Resources	64,092	N/A	8,149	N/A	412,007	N/A	1,834,206	N/A
Development Not Viable	1,205	N/A	564	N/A	40,185	N/A	135,434	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 not applicable 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, 2018 - 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	26,160	9,298	4,017	1,981	1,066	19,097	6,613	2,747	1,281	636

1) NPV as per GLJ Independent Resources Evaluation as of December 31, 2018 and based on GLJ forecast pricing at January 1, 2019.

Reserves and Resources Reconciliation

Resources will generally move from prospective resources to contingent resources, and then to reserves, and ultimately to production. Approximately 100 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 crude 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 in Ante Creek and Pouce Coupe, Alberta with a land position of 1,122 net sections.

GLJ was commissioned to conduct an Independent Resources Evaluation for ARC's lands in the Montney region, including Dawson, Parkland/Tower, Sunrise/Sunset, Sundown, Septimus, Attachie, Red Creek, and Mica in northeast British Columbia, and Pouce Coupe and Ante Creek in Alberta (each, an "Evaluated Area" and, collectively, "Evaluated Areas"). The 2018 Resources Evaluation is the first year that GLJ has incorporated ARC's Ante Creek property into the 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, 2018.

The estimated cost to bring on commercial production from the Development Pending CR for all three product types is approximately $11.6 billion (discounted at 10 per cent is approximately $3.9 billion). The expected timeline to bring these resources onto production ranges from two years to 26 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 horizontal drilling and multi-stage fracturing technology that ARC has already proven to be effective in the Montney.

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 1.00. The remaining CR sub-classes have factors ranging from 0.75 to 1.00.

- Technology Factor: ARC's 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 1.00 for Development Pending CR. Factors less than 1.00 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 0.90.

- 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.

2018 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	89 %	6.0	5.3
Development Unclarified CR	71 %	4.0	2.8
Development Not Viable CR	45 %	1.3	0.6
NGLs (MMbbl)			
Development Pending CR	89 %	285	255
Development Unclarified CR	68 %	230	157
Development Not Viable CR	47 %	86	40
Tight Crude Oil (MMbbl)			
Development Pending CR	82 %	57	47
Development Unclarified CR	50 %	34	17
Development Not Viable CR	40 %	3	1
Total (MMboe)			
Development Pending CR	**89 %**	**1,340**	**1,190**
Development Unclarified CR	**70 %**	**924**	**644**
Development Not Viable CR	**45 %**	**299**	**135**

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.

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 crude 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 Montney, the primary contingencies that prevent the CR from being classified as reserves are for Management and the Board of Directors 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 Montney for the Development Pending CR at the evaluation date. Such projects, in the case of the 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 per cent 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 per cent 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 per cent 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 Consolidated 3rd Edition, Section 1.4.7.2.1.2, 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 per cent.

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 Consolidated 3rd Edition, Section 1.4.7.2.1.3).

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, financial press releases, Information Circular-Proxy Statements and Annual Information Forms. 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.