ARC Resources Ltd.
2019 Annual Information Form

March 6, 2020

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 29, 2020 evaluating the crude oil, natural gas, natural gas liquids, and sulphur reserves attributable to ARC's properties as at December 31, 2019;

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); and

TSX means the Toronto Stock Exchange.

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

SPECIAL NOTES TO READER

REGARDING FORWARD-LOOKING STATEMENTS AND RISK FACTORS

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events of our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek," "anticipate," "budget," "plan," "continue," "estimate," "expect," "forecast," "may," "will," "project," "predict," "potential," "target," "intend," "could," "might," "should," "believe," and similar expressions. In addition, there are forward-looking statements in this Annual Information Form under the headings: *"Statement of Reserves Data and Other Oil and Gas Information"* as to our reserves and future net revenues from our reserves, pricing and inflation rates and future development costs; as to the development of our proved undeveloped reserves and probable undeveloped reserves; as to our future development activities, forward contracts and transportation commitments, reclamation and abandonment obligations, tax horizon, exploration and development activities and production estimates. 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, 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; 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" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves 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 2019 of 139,126 boe per day. ARC’s business activities include the exploration, development and production of crude oil, natural gas and NGLs 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, 2019, ARC had 438 professional, technical and support staff, with 242 employees in the Calgary office and 196 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 subsidiaries or affiliates as of December 31, 2019.

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:

Financial Sustainability and Return on Investment - ARC is committed to paying a meaningful dividend and maintaining a strong balance sheet while delivering competitive returns and creating value for shareholders. With our disciplined, long-term focus on generating returns while managing risk, we demonstrate financial sustainability in all areas of our business.

High Performance People and Culture - ARC has built a high performing, diverse and committed team that is passionate about achieving strong results. ARC’s strong culture of trust, respect, integrity and accountability is the foundation that inspires and motivates our teams to deliver their best performance while meaningfully contributing to ARC’s long-term business success.

High-quality Assets and Operational Excellence - ARC has built a commodity-diverse portfolio of world-class, low-cost assets. We operate with a recognized standard of excellence to generate profitable returns from our investments and manage our operating and capital costs to assure value creation across our business. We are leaders in safety performance and responsible development.

Commercial Activities and Risk Management - ARC is continuously transforming to create value and optimize revenue through upstream and downstream business development and other commercial activities. We actively manage commodity risk through strategic market diversification, financial risk management and commodity optionality.

DEVELOPMENT OF OUR BUSINESS

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

2017

Annual average production of 122,937 boe per day. ARC achieved 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 June 2017. The increased production at Dawson more than offset the total production from non-core assets that were divested in 2016. Crude oil and liquids production volumes from the Saskatchewan assets that were divested in the fourth quarter of 2016 were effectively replaced with new production resulting from ARC's 2017 appraisal activities of the liquids-rich lower Montney horizon.

Proved plus probable reserves of 836 MMboe identified and 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 324 per cent of produced reserves were replaced through capital development activities.

Capital expenditures totaled $829.7 million. During 2017, ARC invested $829.7 million in capital development, before land and net acquisitions and dispositions. Capital investment was directed primarily toward 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. ARC drilled 122 wells in 2017 (62 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 market diversification and financial risk management activities helped to significantly reduce ARC's exposure to weakness in western Canadian natural gas prices. In 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 during the year, 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.

Elimination of the DRIP and SDP. On February 8, 2017, ARC's Board of Directors approved the elimination of the DRIP and SDP. By cancelling 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, 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 and 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 concluded that they outweighed the benefits derived by ARC.

2018

Annual average production of 132,724 boe per day. ARC achieved 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 of assets producing 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 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. During the year 245 per cent of proved plus probable reserves were replaced through capital development activities, and ARC had record proved producing development additions of 82 MMboe in 2018.

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 at several infrastructure projects in 2018, including, the Sunrise Phase II gas processing facility, 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 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 was 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.

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 was 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.

2019

Annual average production of 139,126 boe per day. ARC achieved record full-year average production of 139,126 boe per day in 2019, representing a five per cent increase relative to 2018. The increase in production was driven by increased natural gas production at the Sunrise Phase II gas processing facility and increased liquids-rich lower Montney production in the greater Dawson area.

Proved plus probable reserves of 910 MMboe identified and 164 per cent of produced reserves replaced. GLJ determined ARC's proved plus probable reserves increased four per cent relative to 2018, totaling 910 MMboe as at December 31, 2019. During the year 164 per cent of proved plus probable reserves were replaced through capital development activities. Proved producing reserves were 258 MMboe as at December 31, 2019, representing an increase of six per cent relative to 2018.

Capital budget reduced to preserve balance sheet strength. In June 2019, ARC reduced its budgeted capital program of $775 million for 2019 to $700 million. The adjusted capital budget was consistent with ARC's principles to maintain a strong balance sheet, deliver a sustainable dividend to Shareholders, and demonstrate capital discipline amidst a volatile commodity price backdrop. The reduction to the 2019 capital program related primarily to the deferral of the Attachie West Phase I gas processing and liquids-handling facility.

Capital expenditures totaled $691.5 million. ARC continued to focus on its core Montney businesses in 2019, investing $691.5 million in capital expenditures, before land and net acquisitions and dispositions. A significant focus of ARC's 2019 capital program was on long-term infrastructure projects to support profitable liquids growth in the greater Dawson and Ante Creek areas. 37 per cent of the capital invested in 2019 was to develop infrastructure, with the key focus being on advancing the Dawson Phase IV facility. ARC drilled 87 wells in 2019 (55 liquids-rich natural gas wells and 32 oil wells).

Sunrise Phase II brought to full capacity. ARC brought its Sunrise Phase II gas processing facility to its full capacity of 180 MMcf per day in 2019, redirecting 60 MMcf per day of existing natural gas production that had previously been processed through a third-party facility to ARC's operated Sunrise Phase II facility during the second quarter of 2019, and bringing the final 60 MMcf per day of natural gas production on-stream early in the fourth quarter of 2019.

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 2019. 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 $0.40 per Mcf was realized in ARC's natural gas price in 2019, 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 $0.44 per Mcf.

Recent Developments

Organizational updates. Effective February 6, 2020, Kristen J. Bibby was appointed to the position of Senior Vice President and Chief Financial Officer. Effective February 20, 2020, Terry M. Anderson was appointed to the position of Chief Executive Officer.

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, 2019. The statement of 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 29, 2020. The reserves data summarizes our 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, and the impact of any financial hedging activities. Reserves evaluation includes abandonment and reclamation costs for all active and inactive wells, facilities, and pipelines within all properties with or without attributable reserves as well as future drilling locations attributed proved and/or probable reserves. 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 provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual 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*".

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 in the Montney siltstone are classified as Shale Gas under NI 51-101. ARC's oil reserves 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 6, 2020 news release entitled, *"ARC Resources Ltd. Reports Fourth Quarter and Year-end 2019 Financial and Operational Results and 2019 Reserves Results"*.

Summary of 2019 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	30,342	526	11,954	27,923	70,745	41.2	1,081.1	1,122.4	257,807
Developed Non-Producing	16	—	931	3,605	4,553	1.2	57.6	58.8	14,359
Undeveloped	5,491	—	8,640	54,529	68,661	10.6	1,516.6	1,527.2	323,196
TOTAL PROVED	**35,849**	**526**	**21,526**	**86,057**	**143,958**	**53.1**	**2,655.3**	**2,708.4**	**595,363**
Probable	10,177	179	14,518	47,781	72,655	18.8	1,432.7	1,451.5	314,567
TOTAL PROVED PLUS PROBABLE	**46,026**	**705**	**36,044**	**133,838**	**216,613**	**71.9**	**4,088.0**	**4,159.9**	**909,930**

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	28,004	887	10,469	23,448	62,809	38.9	1,015.8	1,054.7	238,593
Developed Non-Producing	15	—	798	3,075	3,888	1.2	55.0	56.2	13,253
Undeveloped	5,028	—	7,269	48,597	60,893	10.1	1,464.0	1,474.1	306,573
TOTAL PROVED	**33,048**	**887**	**18,536**	**75,119**	**127,590**	**50.1**	**2,534.8**	**2,585.0**	**558,419**
Probable	8,743	282	11,805	39,722	60,552	18.0	1,339.6	1,357.6	286,817
TOTAL PROVED PLUS PROBABLE	**41,791**	**1,169**	**30,341**	**114,841**	**188,142**	**68.1**	**3,874.5**	**3,942.6**	**845,236**

1) NGLs includes associated NGLs for both Conventional and Shale/Tight Reservoirs, and includes condensate, propane and butane.
2) Condensate and Pentanes Plus represent 53 per cent of Proved Developed Producing NGLs and 63 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	2,734	2,574	2,212	1,924	1,707
Developed Non-Producing	263	204	166	141	122
Undeveloped	3,782	2,469	1,687	1,197	872
TOTAL PROVED	**6,779**	**5,247**	**4,066**	**3,262**	**2,702**
Probable	5,129	2,917	1,861	1,295	957
TOTAL PROVED PLUS PROBABLE	**11,908**	**8,164**	**5,927**	**4,556**	**3,659**
After-Tax Net Present Value (1)(2)(3) ($ millions)	**Undiscounted**	**Discounted at 5%**	**Discounted at 10%**	**Discounted at 15%**	**Discounted at 20%**
PROVED					
Developed Producing	2,338	2,280	1,983	1,737	1,549
Developed Non-Producing	197	152	123	103	89
Undeveloped	2,821	1,793	1,179	796	545
TOTAL PROVED	**5,356**	**4,226**	**3,285**	**2,636**	**2,183**
Probable	3,861	2,178	1,372	943	688
TOTAL PROVED PLUS PROBABLE	**9,217**	**6,404**	**4,657**	**3,579**	**2,871**

1) Reflects estimated abandonment and reclamation for all active and inactive areas including all wells (both existing and undrilled), facilities and pipelines, including those areas with no attributed reserves.
2) Based on ARC's estimated tax pools at year-end 2019.
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, 2019 and the related Management's Discussion and Analysis should be consulted for information at the business entity level.

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

Reserves Category ($ millions)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs (1)	Future Net Revenue before Income Taxes	Income Taxes	Future Net Revenue after Income Taxes
Proved Reserves	17,353	1,497	5,654	2,551	873	6,779	1,423	5,356
Proved Plus Probable Reserves	27,555	2,741	8,558	3,379	968	11,908	2,691	9,217

1) Reflects estimated abandonment and reclamation for all active and inactive areas including all wells (both existing and undrilled), facilities and pipelines, including those areas 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)]	369	$11.16/bbl
	Heavy Crude Oil [(2)(3)]	32	$35.93/bbl
	Tight Crude Oil [(2)]	620	$33.59/bbl
	Conventional Natural Gas [(4)]	5	$0.63/mcf
	Shale Gas [(4)]	3,040	$1.30/mcf
	Total	**4,066**	**$7.28/boe**
Proved Plus Probable Reserves	Light Crude Oil and Medium Crude Oil [(2)]	502	$12.01/bbl
	Heavy Crude Oil [(2)(3)]	38	$32.58/bbl
	Tight Crude Oil [(2)]	1,015	$33.61/bbl
	Conventional Natural Gas [(4)]	7	$0.62/mcf
	Shale Gas [(4)]	4,364	$1.23/mcf
	Total	**5,927**	**$7.01/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 NGLs benchmark prices reference GLJ January 1, 2020 price forecasts and exchange rates as follows:

Summary of GLJ January 1, 2020 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 $)
2020	61.00	71.71	50.92	69.56	2.42	2.08	28.68	48.76	77.80	—	0.760
2021	63.00	74.03	54.58	71.81	2.75	2.35	31.09	51.82	79.22	2.0	0.770
2022	66.00	76.92	57.33	74.62	2.90	2.55	34.62	54.62	83.33	2.0	0.780
2023	68.00	80.13	59.71	77.72	3.00	2.65	36.06	56.89	86.54	2.0	0.780
2024	70.00	82.69	62.27	80.21	3.10	2.75	37.21	58.71	89.10	2.0	0.780
2025	72.00	85.26	64.83	82.70	3.20	2.85	38.37	60.53	91.67	2.0	0.780
2026	74.00	87.82	67.40	85.19	3.27	2.91	39.52	62.35	94.23	2.0	0.780
2027	75.81	90.14	69.72	87.44	3.33	2.97	40.56	64.00	96.55	2.0	0.780
2028	77.33	92.09	71.67	89.33	3.40	3.03	41.44	65.38	98.50	2.0	0.780
2029	78.88	94.08	73.65	91.25	3.47	3.09	42.33	66.79	100.49	2.0	0.780
Thereafter	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	2.0	0.780

1) GLJ assigns a value to ARC's existing natural gas physical sales contracts at Dawn, Chicago, Ventura, and Malin consuming markets 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, 2019.
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 2029.

ARC's weighted average prices realized, prior to hedging, for the year ended December 31, 2019, were Cdn$2.12 per Mcf for shale gas and conventional natural gas, Cdn$66.23 per barrel for tight crude oil, light crude oil and medium crude oil, Cdn$58.89 per barrel for heavy crude oil, Cdn$67.61 per barrel for condensate, and Cdn$12.28 per barrel for NGLs.

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, NGLs 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, 2019, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2019 and as at December 31, 2018 include working interest reserves before royalties payable and without including gross royalties receivable. Key highlights include:

- New well classification guidelines in British Columbia resulted in a negative technical revision in Tight Oil in the Total Proved and Total Proved Plus Probable reserves categories due to the reclassification of recovered liquids from oil to condensate. The majority of the negative Tight Oil revisions are directly offset by additions of condensate in the NGLs category.
- Further positive technical revisions in the NGLs category were observed due to strong well performance in the Montney, particularly with ARC's continued focus on the liquids-rich lower Montney horizon.
- ARC divested 1.5 MMboe of Total Proved Plus Probable reserves in 2019, of which 72 per cent were heavy oil volumes associated with non-core assets.
- As a result of lower oil and gas price forecasts year over year, ARC observed a minor negative impact in 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)	Conventional Natural Gas (Bcf)	Shale Gas (Bcf)	Total Gas (Bcf)	Total Oil Equivalent 2019 (Mboe)
PROVED									
December 31, 2018	**38,659**	**1,328**	**28,885**	**66,528**	**135,399**	**51.5**	**2,440.9**	**2,492.4**	**550,803**
Extensions and Improved Recovery (4)	49	—	3,209	13,349	16,606	0.1	308.7	308.8	68,074
Technical Revisions	306	132	(7,068)	12,826	6,196	6.7	136.1	142.8	29,997
Dispositions	(301)	(867)	—	(4)	(1,173)	(0.4)	—	(0.4)	(1,238)
Economic Factors	(102)	—	(44)	(204)	(350)	(0.8)	(7.1)	(7.9)	(1,663)
Production (5)	(2,761)	(66)	(3,457)	(6,437)	(12,721)	(4.0)	(223.4)	(227.3)	(50,610)
December 31, 2019	**35,849**	**526**	**21,526**	**86,057**	**143,958**	**53.1**	**2,655.3**	**2,708.4**	**595,363**
PROBABLE									
December 31, 2018	**10,332**	**302**	**18,971**	**40,572**	**70,177**	**19.2**	**1,528.2**	**1,547.4**	**328,072**
Extensions and Improved Recovery (4)	14	—	26	7,097	7,137	—	6.3	6.3	8,184
Technical Revisions	(30)	75	(4,200)	427	(3,727)	1.3	(96.7)	(95.3)	(19,616)
Dispositions	(30)	(199)	—	(1)	(230)	(0.1)	—	(0.1)	(247)
Economic Factors	(110)	—	(279)	(314)	(703)	(1.7)	(5.0)	(6.7)	(1,825)
December 31, 2019	**10,177**	**179**	**14,518**	**47,781**	**72,655**	**18.8**	**1,432.7**	**1,451.5**	**314,567**
PROVED PLUS PROBABLE									
December 31, 2018	**48,991**	**1,630**	**47,856**	**107,100**	**205,576**	**70.7**	**3,969.1**	**4,039.8**	**878,875**
Extensions and Improved Recovery (4)	63	—	3,235	20,445	23,743	0.1	315.0	315.1	76,258
Technical Revisions	277	207	(11,268)	13,253	2,468	8.0	39.5	47.5	10,381
Dispositions	(331)	(1,066)	—	(5)	(1,403)	(0.5)	—	(0.5)	(1,485)
Economic Factors	(212)	—	(323)	(518)	(1,053)	(2.5)	(12.1)	(14.6)	(3,489)
Production (5)	(2,761)	(66)	(3,457)	(6,437)	(12,721)	(4.0)	(223.4)	(227.3)	(50,610)
December 31, 2019	**46,026**	**705**	**36,044**	**133,838**	**216,613**	**71.9**	**4,088.0**	**4,159.9**	**909,930**

1) NGLs includes associated NGLs for both Conventional and Shale/Tight Reservoirs.
2) Condensate and Pentanes Plus represent 53 per cent of Proved Developed Producing NGLs and 59 per cent of NGLs in the December 31, 2018 opening balance for Probable and Proved Plus Probable.
3) Condensate and Pentanes Plus represent 52 per cent of Proved Developed Producing NGLs and 63 per cent of NGLs in the December 31, 2019 closing balance for Probable and Proved Plus Probable.
4) Reserve additions for Infill Drilling, Extensions and Improved Recovery are combined and reported as "Extensions and Improved Recovery".
5) Production does not include royalty interest volumes and therefore differs from the production shown in the Production History table within this document.

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)
2020	429	488
2021	367	447
2022	437	496
2023	449	554
2024	402	522
Remainder	466	873
Total: Undiscounted	2,551	3,379
Total: Discounted at 10% per Year	1,915	2,457

We expect to fund the development costs of the reserves through a combination of sources including funds from operations and debt.

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 decreased $292 million compared to year-end 2018, to total $3.4 billion at year-end 2019. The year-over-year decrease is driven by the advancement of the Dawson Phase IV facility, which is expected to be brought on-stream in the second quarter of 2020, and capital efficiency improvements related to drilling and completions activities.

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
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
2019	—	5,491	—	—	1,180	8,640	—	10.6	212.4	1,516.6

	NGLs (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2017	7,558	20,583	51,249	238,063
2018	12,956	40,593	61,770	294,677
2019	8,236	54,529	44,810	323,196

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
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
2019	—	2,877	—	—	1,476	10,182	—	6.4	64.6	1,106.7

	NGLs (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2017	7,968	21,287	47,241	240,188
2018	8,607	32,221	55,537	254,298
2019	4,468	37,427	16,717	236,007

As of December 31, 2019, undeveloped reserves represented 54 per cent of total proved reserves and 61 per cent of proved plus probable reserves. Over 87 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 2020 and 2021, focusing on the Dawson, Parkland/Tower, Sunrise, Attachie West and Ante Creek areas. ARC's 2020 capital program includes infrastructure spending for Dawson Phase IV 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 460 total proved, undeveloped locations assigned to be developed over the next eight years in the 2019 evaluation which account for 323 MMboe of reserves volumes. Additional to these total proved undeveloped locations are 156 future development locations assigned probable reserves only, an incremental 34 per cent, which extended the timeline to develop these reserves to approximately 10 years. These probable locations and additional probable reserves assigned to proved locations account for 236 MMboe. The total proved plus probable undeveloped volumes account for 559 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 2020 and 2021) as well as in years beyond 2021, is influenced by many other factors, including the outcomes of the yearly drilling and reservoir evaluations, the price for crude 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”.

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.

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 anticipated future abandonment and reclamation costs for surface leases, wells, facilities and pipelines as well as those with no reserves attributed (aggregated at a property level)**:**

Abandonment & Reclamation Costs Escalated at 2.0%	Undiscounted ($ millions)	Discounted at 10% [(1)] ($ millions)
Total as at December 31, 2019	856.5	80.7
Anticipated to be paid in 2020	25.5	23.2
Anticipated to be paid in 2021	25.0	20.7
Anticipated to be paid in 2022	25.0	18.8

(1) Costs have been discounted in our audited consolidated financial statements for the year ended December 31, 2019 at a liability-specific risk-free rate 1.8 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, 2019, which are available on our SEDAR profile at www.sedar.com.

As at December 31, 2019, ARC had 3,385 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 $968.3 million (undiscounted) and $58.5 million (discounted at 10 per cent) for abandonment and reclamation costs for all wells (both existing and undrilled wells) as well as properties with no attributed reserves.

Additional information related to our reclamation and abandonment obligations can be found in Note 14 "*Asset Retirement Obligation*" in our audited consolidated financial statements for the year ended December 31, 2019, and under the heading "*Asset Retirement Obligation*" in our Management's Discussion and Analysis for the year ended December 31, 2019, 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, 2019. Information in respect of gross and net acres and well counts are as at December 31, 2019. 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, 2019 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. Except as set forth under the heading "*Statement of Reserves Data and Other Oil and Gas Information - Undeveloped Reserves*", there are no material districts to which reserves have been attributed that are capable of producing but which are not producing at December 31, 2019, 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 254,237 gross hectares (239,463 net hectares), which includes land holdings of 657 net Montney sections. ARC drilled 61 gross operated wells in 2019 within the region, with an average working interest of 100 per cent. ARC owns and operates approximately 557 MMcf per day of natural gas and 18,750 barrels per day of liquids processing capacity through its facilities in the region.

Alberta

Northern Alberta

ARC has an average working interest of 85 per cent in the area with approximately 135,021 gross hectares (114,386 net hectares), which includes land holdings of 321 net Montney sections. ARC drilled 15 gross operated wells in 2019 within the northern Alberta region, with an average working interest of 100 per cent.

Pembina

ARC has an average working interest of 82 per cent in approximately 89,785 gross hectares (73,343 net hectares). ARC drilled 11 gross operated Cardium oil wells in 2019, with an average working interest of 96 per cent.

OIL AND GAS WELLS

The following tables set forth the number and status of wells in which ARC had a working interest as at December 31, 2019.

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	118	117	11	10	418	403	214	193
Alberta	1,319	1,054	804	544	116	57	136	66
Total (3)	1,437	1,171	815	554	534	460	350	259

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 the asset retirement obligation, 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 properties with no attributed reserves as at December 31, 2019.

Undeveloped Hectares

	Gross	Net
British Columbia	176,284	168,962
Alberta	123,107	67,520
Total	299,391	236,482

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 2020. There are no material expiries in our core holdings in 2020.

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 material.

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, interest rates 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 16 *"Financial Instruments and Market Risk Management",* to our audited consolidated financial statements for the year ended December 31, 2019 and in the section under the heading *"Risk Management Contracts"* in our Management's Discussion and Analysis for the year ended December 31, 2019, both of which 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 crude oil, natural gas and NGLs 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:

Excess Capacity Above Proved Reserves	0-5 Years	Beyond Five Years
Natural Gas (MMcf/d)	188	103
Crude Oil and NGLs (Mbbl/d)	—	—
Estimated Cost ($ millions)	96	288

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.

ARC's forecast production of proved plus probable reserves based on the GLJ Report is approximately 40 per cent higher than forecast production from proved reserves. 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:

Excess Capacity Above Proved Plus Probable Reserves	**0-5 Years**	**Beyond Five Years**
Natural Gas (MMcf/d)	153	90
Crude Oil and NGLs (Mbbl/d)	—	—
Estimated Cost ($ millions)	81	259

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, 2019, are set forth in Note 21 *"Commitments and Contingencies"* of our audited consolidated financial statements as at and for the year ended December 31, 2019, which have been filed on our SEDAR profile at www.sedar.com.

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, 2019. In 2019, ARC recognized a current income tax recovery of $14.0 million. For 2020, ARC expects current income tax to range from a recovery of two per cent to an expense of three per cent of funds from operations; however, this will be dependent on the commodity price environment and capital spending levels. For more information, please see Note 17 *"Income Taxes"* in our audited consolidated financial statements for the year ended December 31, 2019, 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, 2019:

2019 Capital and Land Expenditures

($ millions)	British Columbia	Alberta	Total
Property Acquisition (Disposition) Costs, Net [1]			
Proved Properties	(0.8)	(4.2)	(5.0)
Undeveloped Properties	0.2	—	0.2
Exploration Costs [2]	2.1	—	2.1
Development Costs [3]	552.6	133.0	685.6
Capitalized Corporate Costs [4]	—	4.5	4.5
Total	**554.1**	**133.3**	**687.4**

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 ($nil).
3) Represents additions to PP&E and includes costs of land acquired ($0.7 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 ARC participated in during the year ended December 31, 2019.

By Well Type	Development Wells [1]		Total [1][2]	
	Gross	Net	Gross	Net
Crude Oil	26	25.55	26	25.55
Natural Gas	61	61.00	61	61.00
Total	**87**	**86.55**	**87**	**86.55**

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, 2019.

PRODUCTION ESTIMATES

The following tables set out the GLJ forecast of the volume of production estimated for the year ended December 31, 2020 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	—	—	—	—	—	—	—	—	280,124	272,341	10,523	9,559	57,210	54,949
Sunrise	—	—	—	—	—	—	—	—	208,664	203,453	122	108	34,900	34,016
Other Properties	7,018	6,487	93	305	8,726	7,432	11,850	11,117	170,005	161,065	11,694	10,288	57,840	53,209
Total Proved	**7,018**	**6,487**	**93**	**305**	**8,726**	**7,432**	**11,850**	**11,117**	**658,794**	**636,859**	**22,338**	**19,954**	**149,950**	**142,174**

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	—	—	—	—	—	—	—	—	18,500	18,144	974	889	4,057	3,913
Sunrise	—	—	—	—	—	—	—	—	4,464	4,357	2	2	746	728
Other Properties	141	113	1	10	978	812	372	373	19,464	18,658	2,013	1,850	6,440	5,956
Total Probable	**141**	**113**	**1**	**10**	**978**	**812**	**372**	**373**	**42,428**	**41,158**	**2,989**	**2,741**	**11,243**	**10,597**

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	—	—	—	—	—	—	—	—	298,624	290,485	11,496	10,448	61,267	58,862
Sunrise	—	—	—	—	—	—	—	—	213,128	207,810	124	110	35,646	34,745
Other Properties	7,159	6,600	94	314	9,704	8,244	12,222	11,491	189,469	179,723	13,707	12,138	64,280	59,165
Total Proved Plus Probable	**7,159**	**6,600**	**94**	**314**	**9,704**	**8,244**	**12,222**	**11,491**	**701,222**	**678,018**	**25,328**	**22,695**	**161,193**	**152,772**

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 expense, and resulting netback for the periods indicated below:

Production History	**Quarter Ended 2019**				**Year Ended**
	March 31	**June 30**	**September 30**	**December 31**	**2019**
Average Daily Production (1)					
Light and Medium Crude Oil (bbl/d)	8,042	7,323	7,110	7,922	7,597
Heavy Crude Oil (bbl/d)	385	687	558	476	527
Tight Crude Oil (bbl/d)	9,824	10,262	9,114	8,685	9,467
Conventional Natural Gas (MMcf/d)	11.5	11.7	11.4	11.9	11.6
Shale Gas (MMcf/d)	621.0	584.7	584.0	657.1	611.7
NGLs (bbl/d) (2)	15,393	17,271	18,798	19,060	17,644
Condensate (bbl/d)	8,210	10,230	10,846	10,937	10,066
Other NGLs (bbl/d) (3)	7,183	7,041	7,952	8,123	7,578
Total (boe/d)	139,054	134,938	134,813	147,650	139,126
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	62.72	70.93	66.33	66.18	66.45
Heavy Crude Oil ($/bbl)	86.70	60.94	48.96	45.56	58.89
Tight Crude Oil ($/bbl)	63.39	69.98	63.79	64.50	65.53
Conventional Natural Gas ($/Mcf)	3.10	2.01	1.61	2.49	2.29
Shale Gas ($/Mcf)	2.78	1.74	1.54	2.36	2.12
NGLs ($/bbl) (2)	46.43	45.42	40.13	44.04	43.84
Condensate ($/bbl)	64.81	71.38	65.70	68.08	67.61
Other NGLs ($/bbl) (3)	25.43	7.71	5.25	11.69	12.28
Total ($/boe)	26.20	23.04	20.46	23.93	23.42

Production History - continued	Quarter Ended 2019				Year Ended
	March 31	June 30	September 30	December 31	2019
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	3.18	6.88	6.33	5.54	5.43
Heavy Crude Oil ($/bbl)	2.60	1.85	0.56	0.85	1.41
Tight Crude Oil ($/bbl)	7.96	8.89	8.94	9.10	8.71
Conventional Natural Gas ($/Mcf)	(0.22)	(1.05)	(0.17)	0.10	(0.33)
Shale Gas ($/Mcf)	0.06	(0.04)	(0.02)	0.03	0.01
NGLs ($/bbl) (2)	4.51	3.88	3.07	3.86	3.79
Condensate ($/bbl)	5.61	6.17	5.01	6.09	5.72
Other NGLs ($/bbl) (3)	3.26	0.55	0.43	0.85	1.23
Total ($/boe)	1.52	1.28	1.26	1.48	1.39
Operating Expense (4)(5)					
Light and Medium Crude Oil ($/bbl)	20.75	21.78	20.12	19.39	20.57
Heavy Crude Oil ($/bbl)	24.14	4.69	5.72	7.51	11.12
Tight Crude Oil ($/bbl)	4.61	3.63	6.54	4.95	4.92
Conventional Natural Gas ($/Mcf)	4.43	4.79	4.59	5.56	4.73
Shale Gas ($/Mcf)	0.61	0.59	0.58	0.50	0.57
NGLs ($/bbl) (2)	5.11	4.74	4.37	4.29	4.59
Condensate ($/bbl)	5.26	4.54	4.00	4.15	4.42
Other NGLs ($/bbl) (3)	4.95	5.02	4.87	4.48	4.80
Total ($/boe)	5.24	5.05	5.05	4.59	4.97
Transportation Paid					
Light and Medium Crude Oil ($/bbl)	1.85	1.65	1.59	1.62	1.68
Heavy Crude Oil ($/bbl)	0.99	0.35	0.01	0.01	0.29
Tight Crude Oil ($/bbl)	3.85	3.67	3.89	3.20	3.66
Conventional Natural Gas ($/Mcf)	0.49	0.48	0.55	0.43	0.49
Shale Gas ($/Mcf)	0.42	0.42	0.41	0.41	0.41
NGLs ($/bbl) (2)	6.07	5.92	5.84	5.66	5.86
Condensate ($/bbl)	6.69	6.38	6.42	6.26	6.42
Other NGLs ($/bbl) (3)	5.35	5.25	5.05	4.85	5.11
Total ($/boe)	2.96	3.00	2.97	2.86	2.94
Netback Received (6)					
Light and Medium Crude Oil ($/bbl)	36.94	40.62	38.29	39.63	38.77
Heavy Crude Oil ($/bbl)	58.97	54.05	42.67	37.19	46.07
Tight Crude Oil ($/bbl)	46.97	53.79	44.42	47.25	48.24
Conventional Natural Gas ($/Mcf)	(1.60)	(2.21)	(3.36)	(3.60)	(2.60)
Shale Gas ($/Mcf)	1.69	0.77	0.57	1.42	1.13
NGLs ($/bbl) (2)	30.74	30.88	26.85	30.23	29.60
Condensate ($/bbl)	47.25	54.29	50.27	51.58	51.05
Other NGLs ($/bbl) (3)	11.87	(3.11)	(5.10)	1.51	1.14
Total ($/boe)	16.48	13.71	11.18	15.00	14.12

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 as defined by ARC 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 NGLs 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, 2019, 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 82 per cent and 18 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, NGLs and crude oil production. For more information on financial contractual obligations relating to ARC's transportation agreements please see Note 21 "*Commitments and Contingencies*" in our audited consolidated financial statements for the year ending December 31, 2019, 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 2019, 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 2019 was $2.12 per Mcf before hedging as compared to $2.37 per Mcf before hedging for 2018. This price was achieved with a portfolio mix that on average through the year, before hedging, received AECO index-based pricing for 42 per cent, Station 2 index-based pricing for 10 per cent, Midwest index-based pricing for 36 per cent, Pacific Northwest index-based pricing for eight per cent and Dawn index-based pricing for four per cent of total production, respectively.

Our natural gas is sold under contracts of various terms at market-based pricing in the regions into which we deliver.

Crude Oil and Natural Gas Liquids

Our liquids production in 2019 comprised approximately 51 per cent light crude oil (greater than 35° API), one per cent medium crude oil (25° to 35° API), one per cent heavy crude oil (less than 25° API) and 47 per cent condensate and other NGLs.

During 2019, our average sales prices before hedging were $66.07 per barrel for light and medium crude oil, $59.72 per barrel for heavy crude oil, and $43.85 per barrel for natural gas liquids including free condensate; these prices compare to 2018 prices of $68.87 per barrel for light and medium crude oil, $48.85 per barrel for heavy crude oil, and $54.39 per barrel for NGLs including free condensate.

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 NGLs are sold on multi-year contracts at market-based pricing. Industry pricing benchmarks for crude oil and NGLs are continuously monitored to ensure optimal netbacks.

SHARE CAPITAL OF ARC RESOURCES

The authorized capital of ARC Resources is an unlimited number of Common Shares without nominal or par value and 50,000,000 preferred shares without nominal or par value issuable in series of which 353,411,132 Common Shares and no preferred shares are outstanding as at December 31, 2019.

The following is a summary of the rights, privileges, restrictions and conditions which attach to the share capital 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. 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, 2019, we had credit facilities consisting of a $950.0 million, financial covenant-based credit facility with a syndicate of major chartered banks, a $40.0 million working capital facility with our agent bank, a $15.0 million letter of credit facility with our agent bank, a $25.0 million letter of credit facility with another major chartered bank and member of the syndicate, and US$577.5 million and $40.0 million of senior notes outstanding. ARC had a net debt balance of $940.2 million outstanding at December 31, 2019, comprised of $877.6 million of long-term debt, $46.2 million of lease obligations and a working capital deficit of $16.4 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 December 6, 2019, the credit facility was extended for another year with a current maturity date of December 15, 2023.

The senior notes outstanding were issued in six tranches and bear interest at a fixed rate. Each tranche requires certain repayments of principal prior to the final maturity thereof. In 2019, ARC executed certain amendments to the note purchase agreements governing its senior notes. The amendments include additional language that modernize the agreements to align with current legislation as well as a modification of certain covenant calculations. The amendments have not been determined to comprise substantial modifications as they have not materially changed the future cash outflows of the senior notes at the time of execution.

The following are financial covenants governing the credit facilities and the Master Shelf Agreement dated March 13, 2019. Capitalized terms are as defined in the credit facility agreement and the Master Shelf Agreement:

- Consolidated Senior Debt not to exceed 3.5 times Consolidated EBITDA;
- Consolidated Total Senior Debt not to exceed 4.0 times Consolidated EBITDA;
- Consolidated Senior Debt not to exceed 55 per cent of Total Capitalization; and
- Consolidated Tangible Assets of the Restricted Group must exceed 85 per cent of Consolidated Tangible Assets.

The following are financial covenants related to the outstanding senior notes. Capitalized terms are as defined in the note purchase agreements:

- Total Indebtedness not to exceed 325 per cent total EBITDA for the most recently completed period of four consecutive quarters;
- Total EBITDA not to be less than 400 per cent of Total Interest Charges for the most recently completed period of four consecutive quarters;
- Total Priority Indebtedness not to exceed two per cent of Total Assets; and
- Total Indebtedness not to exceed 65 per cent of Present Asset Value

ARC is in compliance in all material respects with the terms of the agreements governing the credit facilities and senior notes described above, and has maintained this status throughout the Corporation's 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 13 "*Long-*

Term Debt" of our audited consolidated financial statements for the year ended December 31, 2019, 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*".

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 and a new report will be published in August 2020, 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.

DIRECTORS AND EXECUTIVE OFFICERS

DIRECTORS

The name, municipality, province and country of residence, positions held, period during which such positions have been held and principal occupation during the past five years of each current Director of ARC Resources as at December 31, 2019 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.
Farhad Ahrabi Houston, Texas, USA	2019 Independent	Mr. Ahrabi is the Chief Executive Officer of Cameron LNG.
David R. Collyer Calgary, Alberta, Canada	2016 Independent	Mr. Collyer is an independent business person.
John P. Dielwart Calgary, Alberta, Canada	1996 Independent	Mr. Dielwart is currently the Vice-Chairman of ARC Financial Corporation.
Fred J. Dyment Calgary, Alberta, Canada	2003 Independent	Mr. Dyment 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 [2] Calgary, Alberta, Canada	2016 Independent	Ms. Smith is a Director and Investment Committee Member of ARC Financial Corporation.
Myron M. Stadnyk Calgary, Alberta, Canada	2013 Management Director	Mr. Stadnyk is the President of ARC Resources. Prior to February 2020, he was the President and Chief Executive Officer of ARC Resources.

1) The term of each director is until the next annual meeting of Shareholders, which is scheduled to be held on May 7, 2020.
2) 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 while Ms. Smith was a director. Ms. Smith resigned her directorship on closing of the transaction. Corinthian was later 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, other than Mr. Ahrabi, were elected on May 1, 2019 to hold office until the next annual meeting of Shareholders. Mr. Ahrabi was appointed to the Board of Directors in November 2019. The next annual meeting of Shareholders is scheduled to be held on May 7, 2020.

As at December 31, 2019, the Directors and officers of ARC Resources, as a group, beneficially owned, or controlled or directed, directly or indirectly, 7,047,370 Common Shares or approximately 1.99 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, 2019 are set out below.

Officers	
Name and Municipality of Residence	**Office Held and Principal Occupation During Past Five Years**
Terry M. Anderson Calgary, Alberta, Canada	**Chief Executive Officer** Mr. Anderson is the Chief Executive Officer. Prior to February 2020, he was the Senior Vice President and Chief Operating Officer.
Myron M. Stadnyk (1) Calgary, Alberta, Canada	**President** Mr. Stadnyk's biographical information is included under *"Directors"*.
Kristen J. Bibby Calgary, Alberta, Canada	**Senior Vice President and Chief Financial Officer** Mr. Bibby is the Senior Vice President and Chief Financial Officer. Prior to February 2020, he was the Vice President, Finance and Capital Markets.
P. Van R. Dafoe (2) Calgary, Alberta, Canada	**Former Senior Vice President and Chief Financial Officer** Mr. Dafoe was the Senior Vice President and Chief Financial Officer.
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, Development and Planning** Ms. Conrad is the Vice President, Development and Planning. Prior to December 2019, she was Vice President, Engineering and Planning.
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.
Armin Jahangiri Calgary, Alberta, Canada	**Vice President, Operations** Mr. Jahangiri is the Vice President, Operations. Prior to March 2017, he was the Manager, Engineering North.
Lisa A. Olsen Calgary, Alberta, Canada	**Vice President, Human Resources** Ms. Olsen is the Vice President, Human Resources. Prior to January 2016, she was the Manager, Human Resources.
Grant A. Zawalsky (3) Calgary, Alberta, Canada	**Corporate Secretary** Mr. Zawalsky is the Managing Partner at Burnet, Duckworth & Palmer LLP (law firm).

1) As of February 20, 2020, Mr. Stadnyk retired from the position of Chief Executive Officer of ARC Resources.
2) As of February 6, 2020, Mr. Dafoe retired from ARC Resources.
3) Mr. Zawalsky is not considered to be an "executive officer" of ARC as defined by NI 51-102 as he does not perform a policy-making function in respect of the Corporation.

MEMBERSHIP OF BOARD COMMITTEES

The following chart sets out the membership of the committees of the Board of Directors as at March 6, 2020.

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

1) Mr. Ahrabi joined the Board of Directors in November 2019 and joined the Safety, Reserves & Operational Excellence and Risk Committees in January 2020. Prior to his retirement in May 2019, Mr. Houck was on the Safety, Reserves & Operational Excellence and Risk Committees.

All committees are comprised of independent Directors.

OFFICER BIOGRAPHIES

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

Terry M. Anderson, P. Eng.

Mr. Anderson is the Chief Executive Officer of ARC Resources and has overall management responsibility for the Corporation. Prior to February 2020, he was 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 25 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.

Myron M. Stadnyk, P. Eng.

Mr. Stadnyk is President of ARC Resources. Prior to February 2020, Mr. Stadnyk was President and Chief Executive Officer of ARC Resources. Mr. Stadnyk joined ARC in 1997, as the Corporation's first operations employee. 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.

Kristen J. Bibby, B. Comm., CPA, CA

Mr. Bibby is Senior Vice President and Chief Financial Officer of ARC Resources and oversees the finance, treasury, accounting, tax, risk management, capital markets, marketing, and information technology teams at ARC. 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.

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 20 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.

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. 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, Development and Planning of ARC Resources and is responsible for all development and reservoir engineering, strategic planning, business development and mineral land 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. 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 Sharif 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 C to this Annual Information Form.

MEMBERS OF THE AUDIT COMMITTEE

As of March 6, 2020, 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 45 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 working in or supporting, as a financial advisor, 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. Aside from his capital markets expertise, he brings a broad base of governance experience to ARC having or currently serving as a director or board chair for both private and public boards as well as numerous not-for-profit organizations. Mr. Sembo has a Bachelor of Arts (Economics) from the University of Calgary.

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, 2019 and 2018. 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		2019		2018
Audit Fees	$	720,458	$	693,000
Audit Related Fees (1)	$	—	$	—
Tax Fees (2)	$	—	$	—
All Other Fees (3)	$	52,029	$	38,774

1) The aggregate fees billed by our external auditor for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements but which are not included in audit services fees.
2) The aggregate fees billed by our external auditor for professional services for various tax advice.
3) 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, fees related to valuation services of restricted share awards, and fees for 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.

LEGAL PROCEEDINGS

In May 2018, ARC entered into a purchase and sale agreement with ACCEL Canada Holdings Limited ("ACCEL") to dispose of its interests in certain non-core assets located within the area of Redwater, Alberta for net proceeds of $130.3 million before post-closing adjustments. ARC had recognized in its accounts receivable at December 31, 2018, amounts owing from ACCEL in relation to post-closing adjustments and cash payments made by ARC on behalf of ACCEL after closing of the Transaction and while ARC continued to act as operator of the disposed assets. On May 31, 2019, ARC initiated a lawsuit against ACCEL for approximately $12.0 million for failure to pay certain of these amounts.

On October 23, 2019, ACCEL filed a counterclaim in the Judicial District of Calgary of the Court of Queen's Bench of Alberta against ARC for $200.0 million for damages alleging breaches of contract or misrepresentation related to the transaction. On January 3, 2020, ARC filed its defence to the counterclaim. ARC's claims against ACCEL are currently stayed, though if ACCEL elects to advance its counterclaim against ARC, ARC expects to apply to lift the stay to prosecute its claim against ACCEL. ACCEL has not, at present, indicated an intention to pursue the counterclaim. Management does not expect the outcome of the counterclaim to result in a material outflow of resources by ARC.

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 a monthly dividend to holders of Common Shares on or about the 15th 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 - 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 dividend payments per Common Share were made in the last three completed financial years of ARC:

Dividends	2019	2018	2017
January	$0.05	$0.05	$0.05
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**	**$0.60**

MARKET FOR SECURITIES

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

The following table sets forth the high and low closing prices and the aggregate volume of trading in 2019 of the Common Shares on the TSX for the periods indicated (as quoted by Bloomberg).

Toronto Stock Exchange	High ($)	Low ($)	Volume
January	9.90	8.43	44,118,243
February	10.38	8.84	37,144,353
March	10.02	8.98	60,792,387
April	9.37	8.51	37,993,334
May	8.33	7.36	71,704,593
June	7.36	6.41	32,382,800
July	6.75	6.07	34,838,325
August	6.94	5.49	33,200,603
September	7.30	5.74	47,761,058
October	6.04	5.43	48,924,079
November	6.78	5.85	59,285,168
December	8.18	6.41	54,542,657

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 in the jurisdictions where the companies have assets or operations. While these regulations do not affect ARC'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 legislation and regulations are matters of public record, we are unable to predict what additional laws, regulations 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 and construction of related infrastructure; (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 determine 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 and demand balance and other contractual terms of sale. 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 NGLs 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 and demand balance and other contractual terms of sale.

EXPORTS FROM CANADA

As discussed in greater detail below in *"Environmental Regulation - Federal"*, on August 28, 2019, Bill C-69 came into force, replacing, among other things, the *National Energy Board Act* (the "NEB Act") with the *Canadian Energy Regulator Act* (Canada) (the "CERA"), and replacing the National Energy Board (the "NEB") with the Canadian Energy Regulator ("CER"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGLs from Canada has not changed substantively under the new regime.

Exports of crude oil, natural gas and NGLs from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI* (Oil and Gas) Regulation (the "Part VI Regulation"). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. For natural gas, the maximum duration of an export licence is 40 years; for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. To obtain a crude oil export licence, a mandatory public hearing with the CER is required; however, there is no public hearing requirement for the export of natural gas and NGLs. Instead, the CER will continue to apply the NEB's written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes are not greater than Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CERA and all associated regulations and orders made under the CERA. Following the CER's approval of an export licence, the federal Minister of Natural Resources is mandated to give his or her final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government ("Cabinet") is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect "oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment".

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or 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 CER and the federal government.

As discussed in *"Transportation Constraints and Market Access"* 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

Pipelines

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 jurisdictions 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. The federal government changed the federal approval process with the enactment of the CERA, the *Impact Assessment Act* (Canada), (the "IAA") and the creation of the CER. The stated purpose of this regulatory change is to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator will conduct its regulatory functions compared to the NEB and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty may arise in connection with legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of the relevant environmental review processes. In addition, export pipelines from Canada to the US face additional uncertainty as these pipelines require approvals from 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 and the Gulf Coast, 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 other 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 have led to the delay, suspension or cancellation of many pipeline projects.

With respect to the current state of the transportation and export of crude oil from western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience permitting difficulties in the US and is now expected to be in-service in the latter half of 2020. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC 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. On June 18, 2019, Cabinet re-approved the Trans Mountain Pipeline expansion and directed the NEB to issue a Certificate of Public Convenience and Necessity for the project. Ongoing opposition by Indigenous groups continues to affect the progress of the Trans Mountain Pipeline. Along with its approval of the expansion, the federal government also announced the launch of the first step of a multi-step process of engagement with Indigenous groups for potential Indigenous economic participation in the pipeline. Following a public comment period initiated after the approval, the NEB ruled that NEB decisions and orders issued prior to the Federal Court of Appeal decision that quashed the original Certificate of Public Convenience and Necessity will remain valid unless the CER (having replaced the NEB) decides that relevant circumstances have materially changed such that there is a doubt as to the correctness of a particular decision or order. Construction commenced on the Trans Mountain Pipeline in late 2019, and is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route for the Trans Mountain Pipeline.

In addition to the direct challenges to the Trans Mountain Pipeline expansion, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the "BC EMA") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal answered the reference question unanimously in the negative. This decision was affirmed on appeal to the Supreme Court of Canada. See *"Environmental Regulation - British Columbia"* in these Industry Conditions.

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the Trans Mountain Pipeline expansion. Two First Nations subsequently withdrew from the litigation after reaching an agreement with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four applications for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019.

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company TC Energy Corporation ("TC Energy"), would commence in the first half of 2019, pre-construction work was halted in late 2018 when a United States Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020. Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. Furthermore, the 1.9 kilometer long segment of the pipeline that will cross the Canada-US Border remains dependent on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

Enbridge Open Season

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, would require producers to commit to reserved space in the pipeline for a fixed term. Only 10 per cent of available capacity would be reserved for uncommitted nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service.

On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The CER is expected to establish a timeline for the process in early 2020. Interveners will have the opportunity to make written submissions and an oral hearing will take place later in the year. A final decision from the CER is expected in early 2021.

Marine Tankers

On June 21, 2019, Bill C-48 received royal assent, enacting the *Oil Tanker Moratorium Act*. This Act imposes a ban on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tonnes to or from British Columbia's north coast. See "*Environmental Regulation - Federal*" in these Industry Conditions.

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls per day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. Under this plan, the Alberta Petroleum Marketing Commission proposed to purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program will be cancelled by assigning the transportation contracts to industry proponents. On February 11, 2020, the Government of Alberta announced that it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

In February 2020, the federal government announced that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits following two derailments that led to fires and oil spills in Saskatchewan. These reduced speed limits will remain in effect until April 1, 2020.

Natural Gas

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. However, in September 2019, the CER approved a policy change that TC Energy intended to implement on its NOVA Gas Transmission Ltd. pipeline network (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system.

Additionally, while a number of liquefied natural gas ("LNG") export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, 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. Nonetheless, In October 2018, the proponents of the LNG Canada LNG export terminal announced a positive final investment decision to proceed with the project, which will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia, via the Coastal GasLink pipeline, which will be built and operated by TC Energy (the "CGL Pipeline").

Pre-construction activities began in November 2018, with a completion target of 2025. In late 2019, TC Energy announced that it would sell 65 per cent of its interest in the CGL Pipeline, to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction is expected to close in the first half of 2020. The CGL Pipeline's route was altered as a result of feedback that LNG Canada received from Indigenous groups in the area. On May 1, 2019, the BCOGC approved the current planned route for the CGL Pipeline. However, the CGL Pipeline has faced intense opposition. For example, a challenge to the approval process of the CGL Pipeline was launched in August 2018, contending that it should have been subject to the federal review instead of a provincial review. In July 2019, the NEB confirmed that the CGL Pipeline was properly subject to provincial jurisdiction. In addition, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed pre-construction and construction activities of the CGL Pipeline. Coastal Gaslink Pipeline Ltd. ("CGL") obtained an injunction on December 31, 2019. Enforcement of the injunction started in February 2020. On February 19, 2020, the British Columbia Environmental Assessment Office (the "EAO") directed CGL to re-engage and consult further with Unist'ot'en, one of the Wet'suwet'en clans opposed to the pipeline route, regarding the impacts of the pipeline on a nearby healing centre. The EAO prescribed a 30-day timeline for the completion of these consultations and CGL is permitted to continue pre-construction work in the relevant area.

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 per cent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BCOGC approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being finalized. A project proposed by GNL Québec Inc. continues to make its way through the federal impact assessment process for the construction and operation of an LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd. ("Pieridae"), would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("IA Agency").

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), amended effective October 1, 2019, the Government of Alberta will, on a monthly basis, direct crude oil producers producing more than 20,000 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, representing a reduction of approximately 8.7 per cent of total daily average crude oil production in Alberta during December 2018. The Government of Alberta has indicated that it expects the curtailment rate to continue to gradually drop over the course of 2020 and, depending on the state of export capacity, curtailment may end at the end of 2020.

The Government of Alberta introduced further policy changes to the curtailment program in late 2019, including giving the Minister of Energy the power to set revised production limits for a producer following a merger or acquisition, and creating an exemption from curtailment for newly drilled conventional oil wells. Furthermore, the Government of Alberta created a special production allowance, effective October 28, 2019, that allows crude oil production in excess of a curtailment order, provided that the extra production is shipped out of Alberta by rail.

Based on the current production threshold, ARC is not subject to a curtailment order.

THE NORTH AMERICAN FREE TRADE AGREEMENT AND OTHER TRADE AGREEMENTS

NAFTA / USMCA

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the US and Mexico came into force on January 1, 1994. The three NAFTA signatories have been working towards replacing NAFTA. On November 30, 2018, Canada, Mexico, and the US signed a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "USMCA"). Legislative bodies in the three signatory countries must ratify the USMCA before it comes into force. Mexico's senate ratified the USMCA in June 2019. In late December 2019, the United States' House of Representatives approved the USMCA, and the USMCA received approval from the United States Senate on January 16, 2020. On January 29, 2020, the Government of Canada tabled Bill C-4 to ratify the USMCA. According to Bill C-4, the USMCA will come into force two months after the House of Commons and the Senate pass Bill C-4. Until then, NAFTA will continue to govern the trading relationships among the three countries. As the US remains Canada's primary trading 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 ARC's business.

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.

The Government of Alberta's curtailment program complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply lowered Canada's required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer may be reduced while Canadian crude oil prices are depressed. However, it is not clear whether the USMCA will come into force before the Government of Alberta's curtailment order is repealed.

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.

Other Trade Agreements

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 14 of the 28 national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union. As such, CETA will remain in place until December 31, 2020.

Canada and 10 other countries have agreed on the text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("CPTPP"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among the first seven countries to ratify the agreement - Canada, Australia, Japan, Mexico, New Zealand, Vietnam, 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, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta and British Columbia have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. 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 licences issued after January 1, 2009. Shallow reversion will occur at the conclusion of the primary term of the lease or intermediate term of the licence.

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, NGLs, 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 encourage 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 complete 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 NGLs), 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 Royalty Regimes Summary			
Product	**Oil Wells**	**Gas Wells - Incentive Period**	**Gas Wells - Post Incentive**
Oil - based on oil production	0% to 23%	N/A	N/A
Gas - based on price	8% to 13%	3% or 6%	9% to 27%
Condensate	20%	3% or 6%	20%
Liquids - C2-C5	20%	3% or 6%	20%

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. During this incentive period ARC pays a minimum of three per cent or six per cent depending on the drilling depth.

- The Government of British Columbia also maintains an annual Clean Growth Infrastructure Royalty Credit Program that provides royalty credits under two categories. The "Growth" category of the program is for approved road, pipeline or value-add infrastructure projects and is intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season. The "Sustainability" category of this program is for approved electrification infrastructure for new or retrofits of well pads, wellsite compressors, and other electrical equipment in the field.

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, future changes to environmental legislation, including legislation for air pollution and greenhouse gas ("GHG") emissions, typically measured with reference to carbon dioxide equivalents ("CO2e"), may impose further requirements on operators and other companies in the crude oil and natural gas industry. See also *"Hydraulic Fracturing Regulation"* in these Industry Conditions.

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. 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 August 28, 2019, the CERA and the IAA came into force. At the same time, the NEB Act and the *Canadian Environmental Assessment Act, 2012* ("CEAA 2012") were repealed and the IA Agency replaced the Canadian Environmental Assessment Agency ("CEA Agency").

The legislation implemented under Bill C-69 introduced a number of important changes to the regulatory regime for many major projects and their associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. Now, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions fall into the purview of a group of independent commissioners. The CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of interprovincial and international pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

Designated projects will require an impact assessment as part of their regulatory review. This impact assessment includes expanded criteria that a review panel may consider when reviewing an application. The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and whether the project is in the public interest, as considered with reference to an expanded range of factors. The impact assessment must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include interprovincial or international pipelines that require more than 75 kilometres of new right-of-way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial legislation imposing caps on certain refining, processing and storage facilities will also require an impact assessment.

Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects and there is concern that the changes brought about by Bill C-69 will result in projects not being approved or experiencing increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested.

On May 12, 2017, the federal government introduced Bill C-48 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 passed Bill C-48 as the *Oil Tanker Moratorium Act,* which received royal assent on June 21, 2019. The enactment of this statute may prevent oil pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium and, as a result, may negatively impact the ability of producers to access global markets.

Alberta

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related statutes, 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 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.

On December 16, 2019, British Columbia's new *Environmental Assessment Act* came into force, replacing the previous environmental assessment regime that had been in place since 2002. The changes subject proposed reviewable projects to an enhanced environmental review process similar to the federal environmental assessment process. The new environmental assessment process also aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building that is consistent with British Columbia's recent passage of Bill 41, which affirmed and adopted the United Nations Declaration on the Rights of Indigenous Peoples. Simultaneously with the enactment of the Environmental Assessment Act, the British Columbia Government enacted the accompanying Reviewable Projects Regulation, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project. While many details of the new assessment process remain unknown, the British Columbia Government has released a proposed timetable for the release of supplementary and informational materials through 2020.

In 2018, the British Columbia Government proposed amendments to the BC EMA that would see new heavy oil imports, whether by rail, expanded pipeline, or otherwise, managed through a discretionary permitting process (the "Proposed Amendments"). The Proposed Amendments would have directly affected the transport of heavy oil blends across British Columbia to tidewater through the Trans Mountain Pipeline. In a unanimous decision, the British Columbia Court of Appeal held that the Proposed Amendments were unconstitutional. On January 16, 2020, the Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. On January 29, 2020, the Government of British Columbia indicated that it would not initiate further challenges against the Trans Mountain Pipeline.

HYDRAULIC FRACTURING REGULATION

Hydraulic fracturing is an important and common practice to stimulate production of oil and gas from dense subsurface rock formations. The process involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and gas production. ARC routinely conducts hydraulic fracturing in its drilling and completion programs. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

Alberta

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, Rocky Mountain House, Brazeau, and Red Deer. ARC does have any operations in these areas. However, the AER continues to monitor seismic activity around the province and may extend their reporting requirements as they relate to seismic events to other areas of the province if necessary. The implementation of new regulations or modification of existing regulations may adversely affect ARC's business operation, financial condition, results of operations and prospects.

British Columbia

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. The study resulted in approximately 100 action points for the government to address around water management and handling, engagement and seismicity. At this time there has been no regulatory impact resultant from the study, however the government continues to work with the BCOGC and area operators. 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 Area (the "KSMMA"), in May 2018, the BCOGC issued special notification and monitoring requirements for hydraulic fracturing operators in the KSMMA. 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 occurs. On November 29, 2018, hydraulic fracturing operations of a natural gas producer in the Montney area in British Columbia were suspended after a series of three seismic events, ranging from 3.4 to 4.5 in magnitude which the BCOGC attributed to hydraulic fracturing. The BCOGC allowed the natural gas producer to resume operations in the Montney on October 21, 2019, but their suspension demonstrates the BCOGC's willingness to enforce its enhanced regulatory requirements. The same natural gas producer was also suspended from using a wastewater disposal well in 2019 due to seismicity attributed to the use of that well, demonstrating that the BCOGC's monitoring and oversight of seismic risk is not limited to hydraulic fracturing. The BCOGC is working closely with area operators, continues to monitor seismic events within areas of active oil and gas operations and may implement similar requirements in other areas if necessary.

See "Industry Conditions - Environmental Regulation - British Columbia".

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.

LIABILITY MANAGEMENT RATING PROGRAMS

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"). If a licensee's 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"). 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.

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER stopped posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System. The AER is currently reviewing the AB LMR Program as it no longer considers the LMR value alone to be a good indicator of a company's financial health. It is unclear if, or when, any changes will be made to the current regulatory framework. Any changes to the AB LMR Program may affect ARC's ability to obtain or transfer licenses.

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 becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program, including ARC, 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.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in *Redwater Energy Corporation (Re)* ("Redwater"), 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 Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In response to Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework.The AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee 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 transfers 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. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

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 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 will complete its fifth year on March 31, 2020 but the AER has not released subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural 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 though industry collaboration and economies of scale. Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work conducted on inactive assets. ARC continues to allocate funds to abandonment and reclamation operations and is in compliance with all requirements. ARC will participate in the ABC program in 2020.

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 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.

As a result of certain amendments to the OGAA, on April 1, 2019 a liability-based levy paid to the Orphan Site Reclamation Fund ("OSRF") replaced the orphan site reclamation fund tax paid by permit holders. 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 are required 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 OGAA permits the BCOGC to impose more than one levy in a given calendar year.

Effective May 31, 2019, the *Dormancy and Shutdown Regulation* (the "Dormancy Regulation") establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100 per cent of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BCOGC, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in an annual work plan. The new regulation is expected to have minimal impact on ARC’s corporate liability estimate and the company’s current liability management program in British Columbia.

CLIMATE CHANGE REGULATION

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future 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, including Canada, 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 December 23, 2019, 187 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

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 in 2018, increasing annually until it reaches $50 per tonne in 2022. This system applies 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. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "GGPPA"), which came into force on January 1, 2019. This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20 per tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50 per tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30 per tonne of GHG emissions.

Six provinces and territories have introduced carbon-pricing systems that meet federal requirements: British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories. The federal fuel charge regime took effect in Saskatchewan, Manitoba, Ontario, and New Brunswick on April 1, 2019 and in the Yukon and Nunavut on July 1, 2019. The federal fuel charge regime took effect in Alberta on January 1, 2020.

Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada and the Court is set to hear the appeals in March 2020. On February 24, 2020, the Alberta Court of Appeal determined that the GGPPA is unconstitutional. It is unclear whether the Alberta reference will be appealed and heard with the Saskatchewan and Ontario appeals or, relatedly, whether those scheduled hearings will be delayed as a result. However, each of Saskatchewan, Ontario and Alberta will participate in the scheduled hearings, along with the Attorneys General of Quebec, New Brunswick, Manitoba and British Columbia and various other interested parties.

The federal government has also enacted the *Multi-Sector Air Pollutants Regulation* under the authority of the *Canadian Environmental Protection Act, 1999*, which seeks to regulate certain industrial facilities and equipment types, including boilers and heaters used in the upstream oil and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

Finally, 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, and came into force on 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 natural 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 a Climate Leadership Plan (the "CLP"). Under this strategy, the *Climate Leadership Act* (the "CLA") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. 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.

In June 2019, the Government of Alberta repealed the CLA. The *Carbon Competitiveness Incentives Regime* ("CCIR") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20 per tonne. In accordance with the GGPPA, this will increase to $30 per tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed Technology Innovation and Emissions Reduction ("TIER") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

The TIER regulation operates differently than the former facility-based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10 per cent as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further one per cent reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta previously signaled its intention through the CLP to implement regulations that would lower annual methane emissions by 45 per cent by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "Alberta Methane Regulations") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of Directive 060 complements a previously released update to *Directive 017: Measurement Requirements* for Oil and Gas Operations that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations; however, the Government of Alberta and the federal government have not yet reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations.

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 through 2025 to fund two large-scale carbon capture and storage projects. Both projects will help reduce the CO2 emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year. 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.

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, the Government raised the carbon tax to $35 per tonne in April 2018, and subsequently raised it to $40 per tonne on April 1, 2019. The Government of British Columbia intends to continue raising its carbon tax in $5 increments until it reaches $50 per tonne in 2021.

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. The 2019 provincial budget provided $902 million over three years to support CleanBC, including electric vehicle rebates, incentives for making homes and businesses more energy efficient, and an enhanced climate action tax credit. 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 came 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 ARC'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 ARC's business and the oil and natural gas business generally. ARC's business could also be affected by additional risks and uncertainties not currently known to ARC or that it currently deems to be immaterial. If any of these risks actually occur, it could materially harm ARC's business, financial condition, results of operations, cash flows or impair ARC's ability to implement business plans or complete development activities as scheduled. In that case, the market price of the Common Shares could decline.

Commodity Prices

The prices of crude oil, NGLs and natural gas are highly volatile and have declined significantly in recent years. A sustained decline in these commodity prices could materially and adversely affect ARC's business, financial condition and results of operations.

ARC's revenues, profitability, cash flows and future rate of growth are highly dependent on commodity prices. Commodity prices may fluctuate widely in response to relatively minor changes in the supply of and demand for crude oil, NGLs and natural gas, market uncertainty and a variety of additional factors that are beyond ARC's control, such as:

- domestic and global supply of and demand for crude oil, NGLs and natural gas, as impacted by economic factors that affect gross domestic product growth rates of countries around the world, including impacts from international trade and global health epidemics and concerns;
- market expectations with respect to future supply of crude oil, NGLs and natural gas demand and price changes;
- global crude oil, NGLs and natural gas inventory levels;
- volatility and trading patterns in the commodity-futures markets;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities;
- the capacity of refiners to utilize available supplies of crude oil and condensate;
- weather conditions affecting supply and demand;
- overall domestic and global political and economic conditions;
- actions of the Organization of Petroleum Exporting Countries, its members and other state-controlled oil companies relating to oil price and production controls;
- fluctuations in the value of the US dollar;
- the price and quantity of crude oil, NGLs and LNG imports to and exports from the US and other countries;
- the development of new hydrocarbon exploration, production and transportation methods of technological advancements in existing methods, including hydraulic fracturing;
- capital investments of oil and gas companies relating to the exploration, development and production of hydrocarbons;
- social attitudes or policies affecting energy consumption and energy supply;
- domestic and foreign governmental regulations, including environmental regulations, climate change regulations and taxation; and
- shareholder activism or activities by non-governmental organizations to limit certain sources of capital for the energy sector or restrict the exploration, development and production of crude oil and natural gas; and the effect of energy conservation efforts and the price, availability and acceptance of alternative energies, including renewable energy.

The lack of access to other markets and firm pipeline capacity and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced crude oil and natural gas to market resulting in surplus production and western Canadian realized prices being significantly discounted relative to other markets. See "*Industry Conditions - Transportation Constraints and Market Access*" and "*Industry Conditions - Curtailment*". In addition, the pro-rationing of capacity on interprovincial pipeline systems continues to affect the ability of oil and natural gas companies to export crude oil and natural gas, and could result in ARC's inability to realize the full economic potential of its production. See "*Gathering and Processing Facilities, Pipeline Systems and Rail*" below.

Commodity prices have historically been, and continue to be, extremely volatile. ARC expects this volatility to continue. ARC's risk management arrangements will not fully mitigate the effects of price volatility and may also curtail benefits from future increases in commodity prices. A further or extended decline in commodity prices could materially and adversely affect ARC's future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Significant or extended price declines could also materially and adversely affect the amount of crude oil, NGLs and natural gas that ARC can economically produce, which may result in ARC having to make significant downward adjustments to its reserve estimates. A reduction in production could also result in a shortfall in expected cash flows and require ARC to reduce capital spending or borrow funds or issue equity to cover any such shortfall. Any of these factors could negatively affect ARC's ability to replace its production and its future rate of growth.

Adverse Economic Conditions

Adverse general economic, business and industry conditions could have a material adverse effect on ARC's results of operations and cash flow

The demand for energy, including crude oil, NGLs and natural gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession or other adverse economic or political development in the US, Europe, or Asia, there could be a significant adverse effect on global financial markets and commodity prices. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the US or other countries could adversely affect the global economy. Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as the recent COVID-19 (coronavirus), may adversely affect ARC by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGL and natural gas, (ii) impairing its supply chain, for example, by limiting the manufacturing of materials or the supply of services used in ARC's operations, and (iii) affecting the health of its workforce, rendering employees unable to work or travel. These and other factors disclosed elsewhere in this Annual Information Form that affect the demand for crude oil, NGLs and natural gas and ARC's business and industry could ultimately have an adverse impact on ARC's results of operations and cash flows.

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 ARC's ability to produce and sell its crude oil and natural gas

ARC delivers its products through gathering and processing facilities and pipeline systems. The amount of crude oil, NGLs and natural gas that ARC can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities and pipeline systems. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities 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*" and "*Industry Conditions - Curtailment*". In addition, the pro-rationing of capacity on interprovincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in ARC's inability to realize the full economic potential of its products or in a reduction of the price offered for ARC's production. 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, certain producers have considered rail lines as an alternative means of transportation. ARC currently does not use rail lines as a means of transportation.

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. On August 28, 2019, with the passing of Bill C-69, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the Impact Assessment Agency of Canada replaced the Canadian Environmental Assessment Agency. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

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 material 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.

Political Uncertainty and Geopolitical Risks

ARC's business may be adversely affected by recent political and social events and decisions made in Canada, the United States, Europe and elsewhere

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 attempts to balance between economic development and environmental and social policy. For example, Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project while a minority government in British Columbia remains opposed to the project and has attempted to regulate the transport of heavy oil products into and through British Columbia. Though the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, disputes remain between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction.

The federal Government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Political instability, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry.

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 withdrawn the United States from the Trans-Pacific Partnership and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces US corporate tax rates. This has affected the 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. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. The Canadian Parliament has not yet passed legislation to implement the USMCA. See "*Industry Conditions - The North American Free Trade Agreement and Other Trade Agreements*". The US administration has also taken action with respect to the 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 ARC.

In addition to the political disruption in the US, the impact of the United Kingdom's exit from the European Union 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. Conflict and political uncertainty also continues to progress in the Middle East. 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.

See "*Industry Conditions - Climate Change Regulation*", "*Industry Conditions - Transportation Constraints and Market Access*", "*Industry Conditions - Curtailment*" and "*Industry Conditions - The North American Free Trade Agreement and Other Trade Agreements*".

Reputational Risk Associated with ARC's Operations

ARC relies on its reputation to continue with 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 ARC or as a result of any negative sentiment toward, or in respect of, ARC'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 licences 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 ARC 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 ARC 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 natural resource companies may impact 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 ARC, which may result in limiting ARC's access to capital, increasing the cost of capital, and decreasing the price and liquidity of ARC's securities.

Changing Investor Sentiment

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

A number of factors, including the effects of the use of hydrocarbons on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and 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 governmental 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 ARC 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. See "*Risk Factors - Climate Change*".

Regulatory

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

The oil and gas industry in Canada is a regulated industry. 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. See *"Industry Conditions - Environmental Regulation", "Industry Conditions - Curtailment", "Industry Conditions - Hydraulic Fracturing Regulation"* and *"Risk Factors - Liability Management".*

In order to conduct oil and natural gas operations, ARC will require regulatory permits, licences, 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, licences, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake in the time required or on terms and conditions acceptable to ARC. Any failure to renew, maintain or obtain the required permits, licences, registrations, approvals and authorizations or the revocation or termination of existing permits, licences, registrations, approvals and authorizations may disrupt ARC's operations and could have a material adverse effect on ARC's business, financial position and results of operations. 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 - Liability Management Rating Program*".

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/ or decreased production volumes, adversely affecting ARC's financial position. ARC's operations are dependent upon the availability of water and its ability to dispose of produced water from drilling and production activities. Restrictions on ARC's ability to obtain water or dispose of produced water may have a material adverse effect on its financial condition, results of operations and cash flows

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under high pressure into tight rock formations that were previously unproductive to stimulate the production of crude oil, NGLs and natural gas. 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 shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of crude oil and natural gas that ARC is ultimately able to produce from its reserves.

Water is an essential component of ARC's drilling and hydraulic fracturing processes. Limitations or restrictions on ARC's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If ARC is unable to obtain water to use in its operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on its financial condition, results of operations and cash flows.

In addition, ARC must dispose of the fluids produced from oil and gas production operations, including produced water, which it does directly or through the use of third party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities.

Government authorities may issue orders to temporarily shut down or to curtail the injection depth of existing wells in the vicinity of seismic events. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by ARC or by commercial disposal well vendors that ARC may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in ARC or its vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require ARC or its vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on ARC's business, financial condition and results of operation. See *"Industry Conditions - Environmental Regulation".*

Environmental

Compliance with environmental regulations requires the dedication of a portion of ARC'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 ARC to incur costs to remedy such discharge.

In addition, some of ARC's properties have been operated by predecessors or previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons were not under ARC's control. Joint and several strict liabilities may be incurred in connection with such releases of petroleum hydrocarbons, hazardous substances and wastes on, under, or from ARC's properties. Private parties, including lessors of properties on which ARC operates and the owners or operators of properties adjacent to ARC's operations and facilities where ARC's petroleum hydrocarbons, hazardous substances or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as seek damages for noncompliance with environmental laws and regulations or for personal injury or damage to property or natural resources. Such properties and the substances disposed or released on or under them may be subject to laws which could require ARC to remove previously disposed substances, wastes and petroleum hydrocarbons, remediate contaminated property or perform remedial or closure operations to prevent future contamination, the cost of which could have a material adverse effect on ARC's business, financial condition and results of operations. ARC may not be able to recover some or any of these costs from sources of contractual indemnity or insurance, as pollution and similar environmental risks generally are not insurable or fully insurable, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance.

Although ARC believes that it is 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.

Climate Change

Climate change concerns could result in increased operating costs and reduced demand for ARC's products or securities, while the potential physical effects of climate change could disrupt ARC's production and cause it to incur significant costs in preparing for or responding to those effects

Global climate issues continue to attract public and scientific attention. Numerous reports, such as the Fourth and the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government and investor attention is being paid to global climate issues and to emissions of GHG, including emissions of carbon dioxide and methane from the production and use of crude oil, NGLs and natural gas.

Transition risks

Foreign and domestic governments continue to evaluate and implement policy, legislation and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. See "*Industry Conditions - Climate Change Regulation*" for more information. Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing ARC's operating expenses, and, in the long-term, potentially reducing the demand for oil and natural gas and related products, resulting in a decrease in ARC's profitability and a reduction in the value of its assets. See "*Industry Conditions - Climate Change Regulation*", "*Risk Factors - Non-Governmental Organizations*", and "*Risk Factors - Reputational Risk Associated with ARC's Operations*".

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities or other organizations may make claims against oil and gas companies, including ARC, for alleged personal injury, property damage, or other potential liabilities. While ARC is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by ARC, impact its operations and have an adverse impact on its financial condition.

Given the perceived elevated long-term risks associated with regulatory changes or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing, and providing insurance coverage to oil and gas and related infrastructure businesses and projects. The impact of such efforts require ARC's management to dedicate significant time and resources to these climate change related concerns, may adversely affect ARC's operations, the demand for and price of ARC's securities and may negatively impact ARC's cost of capital and access to the capital markets.

ARC is committed to transparent and comprehensive reporting of its sustainability performance, and considers existing standards such as the Global Reporting Initiative Sustainability Reporting Standards, the Sustainability Accounting Standards Board's documentation, and recommendations issued by the Task Force for Climate Related Financial Disclosures. If ARC is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers or other stakeholders, it's business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities and raise capital may be adversely affected.

Physical risks

Based on ARC's current understanding, the potential physical risks resulting from climate change are long-term in nature associated with a high degree of uncertainty regarding timing, scope and severity of potential impacts. Unlike certain large multi-national, integrated energy companies, ARC does not conduct fundamental research regarding the scientific inquiry of climate change. However, many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict ARC's ability to access its properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of ARC's assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to ARC's assets or cause disruptions to the production and transport of its products or the delivery of goods and services in its supply chain.

Insurance Coverage

Not all risks of conducting oil and natural gas activities are insurable and insurance may become unavailable or only available on reduced amounts of coverage, the occurrence of which would increase ARC's overall risk exposure

ARC maintains insurance coverage as part of its risk management program. However, such insurance may not provide comprehensive coverage in all circumstances, nor are all such risks insurable. ARC self-insures some risks, and its insurance coverage does not cover all the costs arising out of the allocation of liabilities and risk of loss arising from ARC's operations. ARC's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead ARC to decide to reduce or possibly eliminate, coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, ARC's overall risk exposure could be increased.

See *"Risk Factors - Environmental"*, *"Risk Factors - ARC Requires a Skilled Workforce"*, *"Risk Factors - Development and Production Risks"*, *"Risk Factors - Information Technology Systems and Cyber-security"* and *"Risk Factors - Market Price"* for more details.

ARC Requires a Skilled Workforce

An inability to recruit and retain a skilled workforce and key personnel may negatively impact ARC

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 which could have a material adverse effect on ARC's business, financial condition, results of operations and prospects.

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. ARC does not have any key personnel insurance in effect. Contributions of the existing management team to the immediate and near term operations of ARC are likely to be of central importance. In addition, certain of ARC's current employees are senior and have significant 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.

Development and Production Risks

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

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Adverse 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.

Restrictions on the availability and cost of materials and equipment may impede ARC'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 and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede ARC's exploration, development and operating activities.

ARC utilizes multi-well pad drilling where practicable. Well drills on a pad are not placed on production until all wells on the pad are drilled and completed. In addition, problems affecting a single well could adversely affect production from all of the wells on the pad. As a result, multi-well pad drilling can cause delays in the schedule commencement of production, or interruption in ongoing production. These delays or interruptions may cause volatility in ARC's operating results.

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 crude 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 ARC 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. In either event, ARC could incur significant costs.

The long-term commercial success of ARC depends on its ability to find, acquire, develop and commercially produce crude 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 ARC 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 crude 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.

Project Risks

The success of ARC'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 to market crude oil and natural gas depends upon numerous factors beyond ARC's control, including:

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterflood or ARC's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour; and
- regulation of the oil and natural gas industry by various levels of government and governmental agencies.

If cash flow from operating activities and funds from external financing sources are not sufficient to cover ARC's capital expenditure requirements, ARC may be required to reallocate available capital among its projects or modify its capital expenditure plans, which may result in delays to, or cancellation of, certain projects or deferral of certain capital expenditures. Any change to ARC's capital expenditure plans could, in turn, have a material adverse effect on ARC's growth objectives and its business, financial position and results of operations. Because of these factors, ARC could be unable to execute projects on time, on budget, or at all.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with ARC’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. Changes to the AB LMR Program administered by the AER, or other changes to the requirements of liability management programs, may result in significant increases to ARC’s compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in Redwater 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 are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program 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. See "*Industry Conditions - Liability Management Rating Programs*".

Variations in Foreign Exchange Rates and Interest Rates

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

Global 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 our 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 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 ARC 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 ARC's Common Shares.

Third Party Credit Risk

ARC is exposed to credit risk of third party operators or partners of properties in which it has an interest and the failure by counterparties to ARC's risk management activities to perform their obligations

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 a material adverse effect on ARC'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 ARC finds a suitable alternative partner.

The use of derivative risk management transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. ARC is unable to predict changes in a counterparty's creditworthiness or ability to perform. Even if ARC accurately predicts the sudden changes, ARC's ability to negate the risk may be limited depending upon market conditions and the contractual terms of the transactions. During periods of declining commodity prices, ARC's derivative receivable positions generally increase, which increases ARC's counterparty credit exposure.

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.

Information Technology Systems and Cyber-security

Breaches of ARC's cyber-security and loss of, or access to, electronic data may adversely impact ARC's operations and financial position

ARC has become increasingly 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. ARC depends on various information technology systems to estimate reserve quantities, process and record financial data, manage ARC's land base, manage financial resources, analyze seismic information, administer contracts with operators and lessees and communicate with employees and third party partners.

Further, ARC is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of ARC's 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 business activities or ARC's 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 (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years.

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 ARC's systems and obtain confidential information. ARC provides 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 ARC may not be able to properly regulate social media use and preserve adequate records of business activities.

If ARC becomes a victim to a cyber-phishing attack it could result in a loss or theft of ARC’s financial resources or critical data and information, or could result in a loss of control of ARC’s technological infrastructure or financial resources. ARC’s employees are often the targets of such cyber-phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to ARC’s computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

ARC maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts regular cyber-security risk assessments and training and education programs for its employees. ARC also employs encryption protection of its confidential information on all computers and other electronic devices. Despite ARC’s efforts to mitigate such cyber-phishing attacks through education and training, cyber-phishing activities remain a serious problem that may damage its information technology infrastructure. ARC applies technical and process controls in line with industry-accepted standards to protect its information, assets and systems, including a written incident response plan for responding to a cyber-security incident. However, 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 ARC’s performance and earnings, as well as its reputation, and any damages sustained may not be adequately covered by ARC’s current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on ARC’s business, financial condition and results of operations.

Credit Facility Arrangements

Failing to comply with covenants under ARC’s credit facility and senior unsecured notes could result in restricted access to additional capital or being required to repay all amounts owing thereunder

ARC is required to comply with covenants under its credit facility and senior unsecured notes which may, in certain cases, include certain financial ratio tests, which, from time to time, either affect the availability, or price, of additional funding. 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 ARC to comply with such covenants. A failure to comply with covenants could result in default under ARC’s credit facility and senior unsecured notes, which could result in ARC 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 or senior unsecured notes 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.

The Supreme Court of Canada's decision in Redwater may give rise to new covenants and restrictions under ARC’s credit facilities and senior unsecured notes, should LMR levels fall below existing agreed-upon thresholds, including further limitations on asset dispositions and acquisitions. ARC may also be required to provide additional reporting to its lenders regarding its existing and/or budgeted abandonment and reclamation obligations, its decommissioning expenses, its LMR and/or any notices or orders received from an energy regulator in any applicable province. See also "Industry Conditions - Environmental Regulation - Liability Management Rating Programs".

If ARC’s lenders or note holders require repayment of all or a portion of the amounts outstanding under its credit facilities or senior unsecured notes 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 or senior unsecured notes, it may not be on commercially reasonable terms, or terms that are acceptable to ARC. If ARC is unable to repay amounts owing under its credit facilities or senior unsecured notes, the lenders note holders under such credit facilities or senior unsecured notes could proceed to foreclose or otherwise realize upon the collateral (if any) granted to them to secure the indebtedness.

Additional Funding Requirements

ARC 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 operating activities 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, ARC 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 conditions and the domestic lending landscape, 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 ARC to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If ARC's cash flow from operating activities decrease as a result of lower oil and natural gas prices or otherwise, it will affect ARC'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.

Issuance of Debt

Increased debt levels may impair ARC’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 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 ARC 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.

Dividends

The payment of cash dividends could vary

The amount and frequency of future cash dividends paid by ARC, if any, will be 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 ARC, the dividend policy of ARC may be changed from time to time and, as a result, future cash dividends could be reduced or suspended entirely or made less frequently.

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 ARC is required to use cash flow from operating activities to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Competition

ARC competes with other oil and natural gas companies, some of which have greater financial and operational resources or other competitive advantages

The petroleum industry is competitive in all of its phases. ARC competes with numerous other entities in the exploration, development, production and marketing of crude oil and natural gas. ARC's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of ARC and as such, ARC may be at a competitive disadvantage in the identification, acquisition and development of properties that complement ARC's operations. Some of these companies not only explore for, develop and produce crude oil and natural gas, but also carry on refining operations and market crude 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 and less volatility in their earnings and the market price of their equity. ARC's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of crude oil and natural gas include price, process, and reliability of delivery and storage. To a lesser extent, ARC also faces competition from companies that supply alternative sources of energy, such as wind or solar power. Other factors that could affect competition in the marketplace include additional discoveries of hydrocarbon reserves by ARC's competitors, the cost of production and political and economic factors and other factors outside of ARC's control.

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies that may increase the viability of reserves or reduce production costs. Other companies may have greater financial, technical and personnel resources that allow them to implement and benefit from such 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. 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 in a material way.

Litigation

ARC may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect ARC 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 effect on ARC's financial condition. See "*Risk Factors - Climate Change*".

Indigenous Claims

Indigenous claims may affect ARC

Indigenous peoples have claimed Indigenous rights and title in portions of western Canada. Any claims made against sections of land where ARC leases the mineral or surface rights may have an adverse effect on ARC’s business, financial condition, results of operations and prospects. Currently ARC is not aware that any claims have been made in respect of its material properties or assets. In addition, the process of addressing such claims, regardless of the outcome, could be expensive and time consuming and could result in delays in the construction of infrastructure systems and facilities which may have a material adverse effect on ARC’s business and financial results.

Breach of Confidentiality

Breach of confidentiality by a third party could impact ARC'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.

Reserves Estimates

ARC's estimated reserves are based on numerous factors and assumptions which may prove incorrect

There are numerous uncertainties inherent in estimating reserves and the future cash flows attributed to such reserves. The reserves 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:

- commodity prices
- historical production from properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital 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 and probable 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 or taxation and the impact of inflation on costs.

Actual production and cash flows derived from ARC's oil and natural gas reserves 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.

Expansion into New Activities

Expanding ARC's business exposes it to new risks and uncertainties

The operations and expertise of ARC's management are currently focused primarily on crude 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.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved and ARC may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions

ARC considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and ARC's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of ARC. The integration of acquired businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and the resources required to provide such services. In this regard, non-core assets may be disposed of so ARC can focus its efforts and resources more efficiently. Depending on the market conditions for such non-core assets, certain non-core assets of ARC may realize less on disposition than their carrying value on the financial statements of ARC.

Expiration of Licences and Leases

ARC, 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 and the associated abandonment and reclamation obligations may have a material adverse effect on ARC's business, financial condition, results of operations and prospects.

Non-governmental Organizations

ARC'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 licences, and direct legal challenges, including the possibility of climate-related litigation. See "*Industry Conditions - Transportation Constraints and Market Access*". 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 ARC to incur significant and unanticipated capital and operating expenditures.

Availability and Cost of Material and Equipment

Restrictions on the availability and cost of materials and equipment may impede ARC'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 and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede ARC's exploration, development and operating activities.

Title to and Right to Produce from Assets

Defects in the title or rights to produce ARC'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 crude oil and natural gas therefrom, may vary from ARC'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 ARC'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.

Income Taxes

Taxation authorities may reassess ARC'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 ARC calculates its income for tax purposes or could change administrative practices to ARC's detriment.

Market Price

The trading price of ARC's Common Shares is volatile and may remain volatile in the future

The trading price of the securities of oil and natural gas issuers is subject to volatility based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors related to ARC's performance include variations in ARC's financial condition, results of operations, cash flow and prospects. Factors unrelated to ARC's performance include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, and/or negative investor sentiment towards the oil and natural gas industry. In recent years, the volatility of oil and gas commodity prices, and the securities of issuers that explore, develop and produce them, has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. Similarly, recent market prices in the securities of oil and gas producers relative to other industry sectors have led to lower oil and gas representation in certain key equity market indices. The volatility, trading volume and market price of oil and gas issuers have been impacted by increasing investment levels in passive funds that track major indices and only purchase securities included in such indices and subsequently dispose of those securities if they are excluded from such indices, including ARC. In addition, many institutional investors, pension funds and insurance companies, including government-sponsored entities, have implemented investment strategies increasing their investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments. These factors have impacted the volatility and liquidity of certain securities and put downward pressure on the market price of those securities, including the Common Shares. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted and may remain volatile.

Earnings Volatility

Earnings of ARC 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 impairments of net assets in the financial statements on a quarterly basis. Similarly, non-cash gains and reversals of asset impairments may also be recorded from time-to-time. Income statement volatility resulting from such non-cash gains and losses under IFRS may be viewed unfavourably by the market and could result in an inability to borrow funds and/or could result in a decline in the price of the Common Shares.

For more information as to ARC's current accounting policies and future accounting policy changes, see Note 3 "*Summary of Accounting Policies*" and Note 4 "*Changes in Accounting Policies*" in ARC's audited consolidated financial statements as at and for the year ended December 31, 2019 and found on our SEDAR profile at www.sedar.com.

Forward-looking Information

Forward-looking information may prove inaccurate

From time to time, ARC provides forecasts of expected quantities of future crude oil, NGLs and natural gas production and other financial and operating results. These forecasts are based on a number of estimates and assumptions, including that none of the risks associated with ARC's operations summarized in this Annual Information Form occur. Production forecasts, specifically, are based on assumptions such as:

- expectations of production from existing wells and future drilling activity;
- the absence of facility or equipment malfunctions;
- the absence of adverse weather effects;
- expectations of commodity prices, which could experience significant volatility;
- expected well costs; and
- the assumed effects of regulation by governmental agencies, which could make certain drilling activities or production uneconomical.

Shareholders and prospective investors are cautioned not to place undue reliance on ARC's forward-looking information. By its nature, forecasts and other 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 forecasts and other 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 "*Regarding Forward-Looking Statements and Risk Factors*" of this Annual Information Form.

Limited Ability of Residents in the United States to Enforce Civil Remedies

ARC is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. Most of our Directors and all of our Officers and the 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 US. As a result, it may be difficult for investors in the US to effect service of process within the US upon such Directors, Officers and representatives of experts who are not residents of the US or to enforce against them judgments of the US courts based upon civil liability under the US federal securities laws or the securities laws of any state within the US. There is doubt as to the enforceability in Canada against ARC or against any of our Directors, Officers or representatives of experts who are not residents of the US, in original actions or in actions for enforcement of judgments of US courts of liabilities based solely upon the US federal securities laws or securities laws of any state within the US.

Different Reporting Practices in Canada and the United States

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

We incorporate additional information with respect to production and reserves which is either not generally included or prohibited under rules of the Securities and Exchange Commission and practices in the US. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties); however, we also follow the US 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 and Exchange Commission requires that prices and costs be averaged for the 12 months prior to the date of the reserve report.

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 US 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. If a non-resident is a US 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

ARC's 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.

Royalty Regimes

Changes to royalty regimes may negatively impact ARC'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 ARC's operations, less economic. See "*Industry Conditions - Royalties and Incentives*".

Operational Dependence

ARC 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 ARC's financial performance. ARC's return on assets operated by others depends upon a number of factors that may be outside of ARC'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 ARC from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse effect on ARC's financial and operational results. See "*Industry Conditions - Liability Management Rating Programs*".

Hedging

Hedging activities expose ARC 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 crude oil and natural gas production to mitigate the effect of commodity price volatility on ARC's cash flow, and to support ARC's capital budgeting and expenditure plans. 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;
- counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts crude oil and natural gas prices.

On the other hand, failure to protect against decline in commodity prices exposes ARC to reduced liquidity when prices decline. A sustained lower commodity price environment would result in lower realized prices for unprotected volumes and reduce the prices at which ARC would enter into derivative contracts on future volumes. This could make such transactions unattractive, and, as a result, some or all of ARC's production volumes forecasted for 2020 and beyond may not be protected by derivative arrangements.

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.

Dilution

ARC 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 ARC, which may be dilutive to shareholders.

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, October 31, 2018 and December 6, 2019; between ARC Resources and a syndicate of lenders, and an administrative agent, providing for an extendible revolving credit facility up to $950.0 million. The maturity date of the facility was extended to December 15, 2023 under materially similar terms.

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 September 25, 2014, and as amended on September 27, 2019, providing for the issuance and sale of up to an aggregate principal amount of US$350.0 million in notes of which US$150.0 million 3.72% Series E Notes due September 25, 2026, is 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, and September 27, 2019, with respect to US$67.5 million 7.19% Series C Notes due April 14, 2016, US$35.0 million 8.21% Series D Notes due April 14, 2021, and $29.0 million 6.50% Series E Notes due April 14, 2016, of which US$nil, US$14.0 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, and September 27, 2019, with respect to US$150.0 million 5.36% Series F Notes due May 27, 2022, of which US$90.0 million is currently outstanding.

5. Note Purchase Agreement dated as of August 23, 2012, between ARC Resources and various purchasers as amended on September 27, 2019, with respect to US$60.0 million 3.31% Series G Notes due August 23, 2021, US$300.0 million 3.81% Series H Notes due August 23, 2024, and $40.0 million 4.49% Series I Notes due August 23, 2024, of which US$24.0 million, US$300.0 million and $40.0 million, respectively, is currently outstanding.

6. Uncommitted Master Shelf Agreement dated as of March 13, 2019, between ARC Resources and various purchasers, providing for the issuance and sale of up to an aggregate principal amount of US$375.0 million in notes of which $nil 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, 2019. 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 6, 2020, in respect of the Corporation's consolidated financial statements as at December 31, 2019. 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 ARC Resources.

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 7, 2020. Additional financial information is provided in our consolidated financial statements and accompanying Management's Discussion and Analysis for the year ended December 31, 2019, 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 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 as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
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 are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
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, 2019, 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	December 31, 2019	Canada	—	5,927,101	—	**5,927,101**

6. In our opinion, the reserves data, evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, January 29, 2020.

"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 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. 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 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 and other oil and gas information;

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

c) the content and filing of this report.

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

(signed) Terry Anderson
Terry Anderson
Chief Executive Officer

(signed) Larissa Conrad
Larissa Conrad
VP, Development and Planning

(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 5, 2020

APPENDIX C

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.