ARC Resources Ltd. Announces Record 320 Per Cent Replacement of Produced Reserves Through Development Activities in 2017

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CALGARY, Feb. 8, 2018 /CNW/ - (ARX - TSX) ARC Resources Ltd. ("ARC") is pleased to report its 2017 year-end rese
resources information.

"2017 marks ARC's largest addition of development reserves in our company's history, having added 145 MMboe of pr
probable reserves, and replacing 320 per cent of 2017 produced reserves," stated Myron Stadnyk, President and CEO.
assets in northeast British Columbia are becoming increasingly significant to our liquids portfolio, and now account for 2
our total corporate proved plus probable oil reserves and nearly 50 per cent of our total corporate liquids when conside
condensate and natural gas liquids reserves. These meaningful figures are a clear demonstration of ARC's deliberate t
Montney, and most notably into the more liquids-rich portions of the Montney fairway. Our oil and gas portfolio remains
with now over 10.5 billion barrels of tight oil and 106.0 Tcf of shale gas initially-in-place identified across ARC's Montne
northeast British Columbia and Pouce Coupe in Alberta. Supported by our strong financial position and our excellent ca
operating efficiencies, we are excited about the future development opportunities and the value our Montney assets wil
create for our shareholders over the long term."

HIGHLIGHTS

- Replaced 320 per cent of total 2017 production [1], adding 144.6 MMboe of proved plus probable ("2P") reserves
development activities. Over the last 10 years, ARC has replaced an average of 200 per cent or greater producec
through development activities. ARC's 2P reserve life index ("RLI") is 17.4 years [1].
- Replaced 388 per cent of 2017 natural gas production, adding 0.7 Tcf of 2P natural gas reserves. Replaced 129 p
natural gas liquids ("NGLs") production, adding 5.1 MMbbl of 2P NGLs reserves. Replaced 176 per cent of 2017 c
adding 15.4 MMbbl of 2P oil reserves.
- Positive technical revisions of 60 MMboe (2P) were realized, predominantly in Sunrise and Dawson, reflecting the
performance from ARC's Montney assets.
- Proved developed producing ("PDP") reserves increased by eight per cent, from 212 MMboe to 230 MMboe. The
PDP reserves was due to both development adds from ARC's core Montney properties, as well as positive techni
reflecting ARC's increased confidence in well performance.
- Total proved reserves increased by 19 per cent from 426 MMboe to 506 MMboe, and 2P reserves increased by 1
737 MMboe to 836 MMboe.
- Material reserves growth was realized in ARC's Montney assets, particularly in Attachie, Dawson, Parkland/Towe
Pouce Coupe.
- Three-year average Finding, Development and Acquisition ("FD&A") [1] costs were $5.52 per boe for proved rese
per boe for 2P reserves, including Future Development Capital ("FDC").
- Finding and Development ("F&D") costs [1] were $6.41 per boe for 2P reserves, $7.40 per boe for proved reserve
boe for proved producing reserves, excluding FDC.
- Before-tax net present value ("NPV") for 2P reserves, discounted at 10 per cent, is $5.7 billion at year-end 2017,
GLJ Petroleum Consultants ("GLJ") commodity price forecast at January 1, 2018.

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  - Year-end 2016 2P NPV of $5.8 billion on GLJ price forecast at January 1, 2017.
  - Year-end 2017 2P NPV of $6.9 billion on GLJ price forecast at January 1, 2017. Reserves additions increas approximately 18 per cent.
  - Year-end 2017 2P NPV of $5.7 billion on GLJ price forecast at January 1, 2018. Price deck reduced value b 18 per cent.
- Increased NE BC Montney acreage, including lands at Pouce Coupe in Alberta, by four per cent in 2017 with the high-quality net sections, strengthening ARC's existing position across core areas of Attachie and greater Dawso
- ARC updated an Independent Resources Evaluation (the "Resources Evaluation" or "Independent Resources Ev lands in the NE BC Montney region, including lands at Pouce Coupe in Alberta. The updated evaluation realized the identified resource base on ARC's NE BC Montney lands. The shale gas Total Petroleum Initially-in-Place ("T to 106.0 Tcf in 2017, and tight oil TPIIP was 10.5 billion barrels of oil in 2017 [2].

(1)	"Reserve replacement", "reserve life index" or "RLI", "Finding, Development and Acquisitions costs" or "FD&A costs", and "Finding and Development costs" or "F&D costs" do not have standardized meanings. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" contained in this news release.
(2)	The year-end 2017 Resources Evaluation complies with current Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") guidelines. The Resources Evaluation volumes provided are the "Best Estimate" case. Year-end 2017 and 2016 TPIIP estimates utilize a one per cent porosity cut-off for shale gas and tight oil based upon "Best Estimate" case.

2017 INDEPENDENT RESERVES EVALUATION

GLJ conducted an Independent Reserves Evaluation (the "Reserves Evaluation" or "Independent Reserves Evaluation' December 31, 2017, which was prepared in accordance with definitions, standards and procedures contained in the C and National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). The reserves evaluati on GLJ forecast pricing and foreign exchange rates at January 1, 2018, as outlined in Table 1 below.

Reserves included herein are stated on a company gross basis (working interest before deduction of royalties without t any royalty interest) unless otherwise noted. In addition to the detailed information disclosed in this news release, more information will be included in ARC's Annual Information Form ("AIF") for the year ended December 31, 2017, which wi on ARC's website at www.arcresources.com and filed on SEDAR at www.sedar.com on or before March 30, 2018.

Based on this Independent Reserves Evaluation, ARC's reserves profile as at December 31, 2017 is summarized belo

- 13 per cent increase in 2017 2P reserves to 836 MMboe compared to 737 MMboe of 2P reserves at year-end 20 are comprised of 3.8 Tcf of natural gas, 131 MMbbl of oil [1] and 73 MMbbl of NGLs at year-end 2017. The NGLs of 48 per cent condensate (35 MMbbl), 32 per cent propane (23 MMbbl), and 20 per cent butane (14 MMbbl).
- 144.6 MMboe of 2P reserve additions from development activities (including revisions), before net acquisitions ar negative 0.5 MMboe and 2017 production of 44.7 MMboe. Technical revisions of 60.1 MMboe more than offset th MMboe due to economic factor revisions resulting from the decrease in commodity price forecasts since year-end
- Replaced 320 per cent of total 2017 production, adding 144.6 MMboe of 2P reserves through development activi production of 44.7 MMboe.
- Total proved reserves account for 61 per cent of 2P reserves.
- PDP reserves represent 45 per cent of total proved reserves and 27 per cent of 2P reserves.
- Oil and NGLs comprise 24 per cent of 2P reserves and natural gas comprises 76 per cent of 2P reserves, using t accepted boe conversion ratio of six Mcf to one barrel.

- Additions from development activities resulted in increased reserves, coupled with increased FDC for these devel activities, resulting in one-year 2P F&D costs, including FDC, of $9.61 per boe for 2017, and $5.52 per boe for the average. Proved F&D costs, including FDC, were $9.34 per boe for 2017 and $7.91 per boe for the three-year av
- Strong 2P RLI of 17.4 years at year-end 2017 was up from 16.4 years at year-end 2016. The increase in RLI is at strong reserves growth in 2017. For details on ARC's 2018 production guidance, see the November 9, 2017 news entitled, "ARC Resources Ltd. Announces $690 Million Capital Program for 2018" available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.
- Recycle ratio (2) of 2.5 times and 2.7 times for the current year and the three-year average, respectively, for 2P re on current and three-year average F&D costs, excluding FDC, which are based on current and three-year averag netbacks (3) of $15.94 per boe and $15.32 per boe, respectively.
- FDC increased by $460 million compared to year-end 2016, to total $3.2 billion at year-end 2017, and was driven of future development activities in ARC's core Montney acreage.
- Before-tax NPV for 2P reserves, discounted at 10 per cent, is $5.7 billion at year-end 2017.
- Abandonment and reclamation costs increased from $462 million (undiscounted) at year-end 2016 to $527 millior at year-end 2017. These costs have been included in the 2P reserves, which account for the abandonment and re wells to which reserves have been attributed.

(1)	Total oil includes light, medium, heavy, and tight oil. See Tables 2 and 3 for detailed breakdown.
(2)	"Recycle ratio" does not have a standardized meaning. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" contained in this news release.
(3)	"Operating netback" is a non-GAAP measure and does not have a standardized meaning under IFRS. See "Non-GAAP Measures" contained within ARC's Management's Discussion and Analysis ("MD&A").

Table 1

GLJ Price Forecast	WTI Crude Oil		Edmonton Light Oil		AECO Natural Gas		Foreign Exchange	
	(US$/bbl)		(Cdn$/bbl)		(Cdn$/MMBtu)		(US$/Cdn$)	
	2018	2017	2018	2017	2018	2017	2018	2017
2018	59.00	59.00	70.25	72.26	2.20	3.10	0.790	0.775
2019	59.00	64.00	70.25	75.00	2.54	3.27	0.790	0.800
2020	60.00	67.00	70.31	76.36	2.88	3.49	0.800	0.825
2021	63.00	71.00	72.84	78.82	3.24	3.67	0.810	0.850
2022	66.00	74.00	75.61	82.35	3.47	3.86	0.820	0.850
2023	69.00	77.00	78.31	85.88	3.58	4.05	0.830	0.850
2024	72.00	80.00	81.93	89.41	3.66	4.16	0.830	0.850
2025	75.00	83.00	85.54	92.94	3.73	4.24	0.830	0.850
2026	77.33	86.05	88.35	95.61	3.80	4.32	0.830	0.850
2027 (1)	78.88		90.22		3.88		0.830	0.850
Escalate thereafter at	+2% / year	+2% / year	+2% / year	+2% / year	+2% / year	+2% / year	0.830	0.850

(1)	Escalated at two per cent per year starting in 2027 in the January 1, 2018 GLJ price forecast with the exception of foreign exchange, which remains flat.

Table 2

Reserves Summary Company Gross (1)	Light, Medium and Heavy Oil (2) (Mbbl)	Tight Oil (Mbbl)	NGLs (Mbbl)	Natural Gas (3) (MMcf)	2017 Oil Equivalent (Mboe)	2016 Oil Equivalent (Mboe)
Proved Developed Producing	51,470	14,650	17,780	873,778	229,530	212,341
Proved Developed Non-producing	1,030	2,856	4,230	183,661	38,726	10,930
Proved Undeveloped	7,132	16,438	20,582	1,163,457	238,063	202,656
Total Proved	59,632	33,944	42,593	2,220,896	506,319	425,927
Proved plus Probable	79,151 (4)	51,489	72,570	3,797,360 (5)	836,103	736,733

(1)	Amounts may not add due to rounding.
(2)	Light, Medium and Heavy Oil includes light, medium and heavy crude oil product types, as heavy oil makes up three per cent of total light, medium and heavy crude oil and is considered to be immaterial.
(3)	Natural Gas includes shale gas and conventional natural gas product types, as conventional natural gas makes up three per cent of total gas and is considered to be immaterial.
(4)	Proved plus Probable Light, Medium and Heavy Oil closing balance by percentage weighting of product type: approximately 97 per cent light and medium crude oil and three per cent heavy crude oil.
(5)	Proved plus Probable Natural Gas closing balance by percentage weighting of product type: approximately 97 per cent shale gas and three per cent conventional natural gas.

Table 3

Reserves Reconciliation Company Gross (1)	Light, Medium and Heavy Oil (2) (Mbbl)	Tight Oil (Mbbl)	NGLs (Mbbl)	Natural Gas (3) (MMcf)	Oil Equivalent (Mboe)
Proved Producing					
Opening Balance, January 1, 2017	53,259	13,697	13,040	794,069	212,341
Discoveries	—	—	—	—	—
Extensions and Improved Recovery (4)	1,316	4,071	2,918	92,902	23,789
Technical Revisions	1,811	1,422	5,885	186,594	40,217
Acquisitions	—	—	—	22	4
Dispositions	—	—	(3)	(307)	(54)
Economic Factors	(597)	(111)	(78)	(7,772)	(2,081)
Production	(4,320)	(4,428)	(3,983)	(191,729)	(44,685)
Ending Balance, December 31, 2017	51,470	14,650	17,780	873,778	229,530
Total Proved					
Opening Balance, January 1, 2017	60,155	28,628	38,064	1,794,476	425,927
Discoveries	—	—	—	—	—
Extensions and Improved Recovery (4)	2,889	8,082	7,403	203,905	52,359
Technical Revisions	1,545	2,620	1,552	435,982	78,381

Acquisitions	—	—	—	22	4
Dispositions	—	—	(32)	(1,200)	(232)
Economic Factors	(637)	(958)	(412)	(20,560)	(5,434)
Production	(4,320)	(4,428)	(3,983)	(191,729)	(44,685)
Ending Balance, December 31, 2017	59,632	33,944	42,593	2,220,896	506,319
Proved plus Probable					
Opening Balance, January 1, 2017	79,735	44,261	71,504	3,247,395	736,733
Discoveries	—	—	—	—	—
Extensions and Improved Recovery (4)	4,268	8,720	13,078	386,253	90,441
Technical Revisions	238	3,445	(7,663)	384,477	60,099
Acquisitions	—	—	—	26	5
Dispositions	—	—	(76)	(2,759)	(536)
Economic Factors	(771)	(509)	(290)	(26,303)	(5,954)
Production	(4,320)	(4,428)	(3,983)	(191,729)	(44,685)
Ending Balance, December 31, 2017	79,151 (5)	51,489	72,570	3,797,360 (6)	836,103

(1)	Amounts may not add due to rounding.
(2)	Light, Medium and Heavy Oil includes light, medium and heavy crude oil product types, as heavy oil makes up three per cent of total light, medium and heavy crude oil and is considered to be immaterial.
(3)	Natural Gas includes shale gas and conventional natural gas product types, as conventional natural gas makes up three per cent of total gas and is considered to be immaterial.
(4)	Reserves additions for infill drilling, improved recovery, and extensions are combined and reported as "Extensions and Improved Recovery".
(5)	Proved plus Probable Light, Medium and Heavy Oil closing balance by percentage weighting of product type: approximately 97 per cent light and medium crude oil and three per cent heavy crude oil.
(6)	Proved plus Probable Natural Gas closing balance by percentage weighting of product type: approximately 97 per cent shale gas and three per cent conventional natural gas.

Reserve Life Index

ARC's 2P RLI was 17.4 years at year-end 2017, and the proved RLI was 10.5 years. The RLIs are derived by dividing the appropriate GLJ reserves category by ARC's 2018 production guidance midpoint of 132,000 boe per day, which is contingent upon the execution of a $690 million capital program for 2018. The 2P RLI has been maintained at greater than 15 years since year-end 2010 as a result of successful delineation and reserves growth of ARC's Montney assets in northeast British Columbia. ARC's annual average production has increased from 96,087 boe per day in 2013 to 122,937 boe per day in 2017. Table 4 summarizes ARC's historical RLI.

Table 4

Reserve Life Index	2017 (1)	2016	2015	2014	2013
Total Proved	10.5	9.6	9.1	8.5	9.1
Proved plus Probable	17.4	16.4	15.9	15.0	15.5

(1)	Based on production guidance midpoint of 132,000 boe per day for 2018.

Net Present Value Summary

ARC's oil, natural gas and NGLs reserves were evaluated using GLJ's commodity price forecasts at January 1, 2018. The NPV is prior to provision for interest, debt service charges, and general and administrative expenses. It should not be assumed that the NPV of future net revenue estimated by GLJ represents the fair market value of the reserves. The NPV of ARC's reserves decreased relative to year-end 2016, despite material reserve adds in 2017, primarily due to lower forecasted prices by GLJ. NPVs on both a before- and after-tax basis are presented in Table 5.

Table 5

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

(1)	Amounts may not add due to rounding.
(2)	Based on NI 51-101 company net interest reserves and GLJ price forecasts and costs at January 1, 2018.
(3)	Based on ARC's estimated tax pools at year-end 2017.
(4)	The after-tax NPV of the future net revenue attributed to ARC's oil and natural gas properties reflects the tax burden on the properties on a standalone basis. It does not consider the business entity tax-level situation or tax planning, nor does it provide an estimate of the value at the level of the business entity, which may be significantly different. ARC's audited consolidated financial statements and notes and MD&A should be consulted for information at the business entity level.

At a 10 per cent discount factor, and on a before-tax basis, the future net revenue attributed to the proved producing reserves constitutes 64 per cent of the future net revenue attributed to the total proved reserves (NPV10 before-tax), similar to the future net revenue attributed to the total proved reserves, which accounts for 67 per cent of the future net revenue attributed to the 2P reserves (NPV10 before-tax).

Future Development Capital

FDC reflects the independent evaluator's best estimate of what it will cost to bring the proved and probable developed and undeveloped reserves on production. Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities, and changes in capital cost estimates based on improvements in well design and performance, as well as changes in service costs. FDC increased by $460 million compared to year-end 2016, to total $3.2 billion at year-end 2017. The increase in FDC was driven by development activities in the Montney and is consistent with the increase in 2P reserves volumes.

Table 6 outlines GLJ's estimated FDC required to bring total proved and total 2P reserves on production.

Table 6

Future Development Capital [(1)(2)]	Total Proved	Total Proved plus Probable
($ millions)		
2018	500	621
2019	513	602
2020	450	564
2021	290	612
2022	119	313
Remainder	278	504
Total FDC, Undiscounted	2,150	3,215
Total FDC, Discounted at 10%	1,666	2,413

(1)	Amounts may not add due to rounding.
(2)	FDC as per GLJ Independent Reserves Evaluation as of December 31, 2017 and based on GLJ forecast pricing at January 1, 2018.

ARC's 2018 capital budget is $690 million, 10 per cent higher than the proved plus probable FDC forecast for 2018. The total proved plus probable FDC, undiscounted, is less than five times ARC's 2018 capital budget. For details on ARC's 2018 capital budget, see the November 9, 2017 news release entitled, "ARC Resources Ltd. Announces $690 Million Capital Program for 2018" available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

Finding, Development and Acquisition Costs

ARC's 2017 F&D costs were $6.41 per boe and $7.40 per boe for 2P and proved reserves, respectively, excluding FDC ($9.61 per boe and $9.34 per boe, respectively, for 2P and proved reserves, including FDC). ARC's three-year average F&D costs were $5.73 per boe for 2P reserves and $6.88 per boe for proved reserves, excluding FDC. The low F&D costs are attributed to the high-quality nature of ARC's portfolio of assets, strong results from ARC's development program, and meaningful reserves growth, notably at Sunrise, Dawson and Parkland/Tower. ARC's 2017 F&D costs include approximately $98 million of capital investment on Crown lands, with no significant associated reserves or production associated with these acquisitions in the current year.

Including net acquisitions, ARC's 2017 Finding, Development and Acquisition [(1)] costs were $6.45 per boe for 2P reserves and $7.43 per boe for proved reserves, excluding FDC ($9.64 per boe and $9.37 per boe, respectively, for 2P and proved reserves, including FDC). The three-year average FD&A costs were $4.54 per boe for 2P reserves and $5.24 per boe for proved reserves, excluding FDC. ARC's low FD&A costs reflect ARC's focus on high-quality assets, cost management, and allocation of resources and capital investment to high rate of return projects. ARC's 2017 FD&A costs include approximately $98 million of capital investment on Crown lands, with no significant associated reserves or production. Additionally, ARC's FD&A costs incorporate the net acquisition of properties with associated reserves and production for approximately $2.5 million in 2017.

(1)	"Finding, development and acquisition costs" or "FD&A costs" does not have a standardized meaning. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" contained in this news release.

Table 7 highlights ARC's reserves, F&D costs, FD&A costs and the associated recycle ratios for the past three years.

Table 7

Reserves (Company Gross), Capital Expenditures and Operating Netbacks (1)(2)(3)	2017	2016	2015
Reserves (Mboe)			
Proved Producing	229,530	212,341	221,509
Total Proved	506,319	425,927	393,327
Proved plus Probable	836,103	736,733	686,851
Capital Expenditures ($ millions)			
Exploration and Development	927.3	456.1	548.3
Net Property Acquisitions (Dispositions)	2.5	(532.5)	(74.4)
Total Capital Expenditures	929.8	(76.4)	473.9
Operating Netbacks ($/boe)			
Operating Netback	15.94	13.45	16.61
Operating Netback – Three-year Average	15.32	20.83	25.81

(1)	Amounts may not add due to rounding.
(2)	"Operating netback" is a non-GAAP measure and does not have a standardized meaning under IFRS. See "Non-GAAP Measures" contained within ARC's MD&A.
(3)	Operating netbacks exclude other income.

Table 7a

Finding and Development Costs, excluding FDC (1)(2)(3)(4)	2017	2016	2015
Company Gross			
Proved Producing			
Reserve Additions (MMboe)	61.9	43.6	66.0
F&D Costs ($/boe)	14.98	10.46	8.31
F&D Recycle Ratio	1.1	1.3	2.0
F&D Costs – Three-year Average ($/boe)	11.26	12.77	15.05
F&D Recycle Ratio – Three-year Average	1.4	1.6	1.7
Total Proved			
Reserve Additions (MMboe)	125.3	88.6	66.9
F&D Costs ($/boe)	7.40	5.15	8.20
F&D Recycle Ratio	2.2	2.6	2.0
F&D Costs – Three-year Average ($/boe)	6.88	9.56	14.13
F&D Recycle Ratio – Three-year Average	2.2	2.2	1.8
Proved plus Probable			
Reserve Additions (MMboe)	144.6	113.5	78.7
F&D Costs ($/boe)	6.41	4.02	6.97
F&D Recycle Ratio	2.5	3.3	2.4
F&D Costs – Three-year Average ($/boe)	5.73	7.19	10.36
F&D Recycle Ratio – Three-year Average	2.7	2.9	2.5

(1)	F&D costs take into account reserves revisions during the year on a per boe basis.
(2)	The aggregate of the exploration and development costs incurred in the financial year and the changes during that year in estimated future development costs may not reflect the total F&D costs related to reserves additions for that year.
(3)	"Finding and development recycle ratio" or "F&D recycle ratio" does not have a standardized meaning. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" contained in this news release.
(4)	2015 and 2016 recycle ratios have been restated to reflect the exclusion of other income in operating netbacks.

Table 7b

Finding and Development Costs, including FDC (1)(2)(3)(4)	2017	2016	2015
Company Gross			
Proved Producing			
Change in FDC ($ millions)	35.5	19.0	(53.5)
Reserve Additions (MMboe)	61.9	43.6	66.0
F&D Costs ($/boe)	15.55	10.90	7.49
F&D Recycle Ratio	1.0	1.2	2.2
F&D Costs – Three-year Average ($/boe)	11.27	12.76	15.19
F&D Recycle Ratio – Three-year Average	1.4	1.6	1.7
Total Proved			
Change in FDC ($ millions)	242.9	581.3	(535.6)
Reserve Additions (MMboe)	125.3	88.6	66.9
F&D Costs ($/boe)	9.34	11.71	0.19
F&D Recycle Ratio	1.7	1.1	87.4
F&D Costs – Three-year Average ($/boe)	7.91	10.11	11.61
F&D Recycle Ratio – Three-year Average	1.9	2.1	2.2
Proved plus Probable			
Change in FDC ($ millions)	461.9	236.5	(770.3)
Reserve Additions (MMboe)	144.6	113.5	78.7
F&D Costs ($/boe)	9.61	6.10	(2.82)
F&D Recycle Ratio	1.7	2.2	(5.9)
F&D Costs – Three-year Average ($/boe)	5.52	6.48	8.11
F&D Recycle Ratio – Three-year Average	2.8	3.2	3.2

(1)	F&D costs take into account reserves revisions during the year on a per boe basis.
(2)	The aggregate of the exploration and development costs incurred in the financial year and the changes during that year in estimated future development costs may not reflect the total F&D costs related to reserves additions for that year.
(3)	"Finding and development recycle ratio" or "F&D recycle ratio" does not have a standardized meaning. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" contained in this news release.
(4)	2015 and 2016 recycle ratios have been restated to reflect the exclusion of other income in operating netbacks.

Table 7c

Finding, Development and Acquisition Costs, excluding FDC (1)(2)(3)(4)	2017	2016	2015
Company Gross			
Proved Producing			
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	61.9	34.0	53.4
FD&A Costs ($/boe)	15.03	(2.25)	8.88
FD&A Recycle Ratio	1.1	(6.0)	1.9
FD&A Costs – Three-year Average ($/boe)	8.89	11.15	17.02
FD&A Recycle Ratio – Three-year Average	1.7	1.9	1.5
Total Proved			
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	125.1	75.7	52.6
FD&A Costs ($/boe)	7.43	(1.01)	9.00
FD&A Recycle Ratio	2.1	(13.3)	1.8
FD&A Costs – Three-year Average ($/boe)	5.24	8.13	15.98
FD&A Recycle Ratio – Three-year Average	2.9	2.6	1.6
Proved plus Probable			
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	144.1	93.0	55.5
FD&A Costs ($/boe)	6.45	(0.82)	8.54
FD&A Recycle Ratio	2.5	(16.4)	1.9
FD&A Costs – Three-year Average ($/boe)	4.54	6.31	11.88
FD&A Recycle Ratio – Three-year Average	3.4	3.3	2.2

(1)	FD&A costs take into account reserves revisions during the year on a per boe basis.
(2)	The aggregate of the exploration and development costs incurred in the financial year and the changes during that year in estimated future development costs may not reflect the total F&D costs related to reserves additions for that year.
(3)	"Finding, development and acquisition recycle ratio" or "FD&A recycle ratio" does not have a standardized meaning. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" contained in this news release.
(4)	2015 and 2016 recycle ratios have been restated to reflect the exclusion of other income in operating netbacks.

Table 7d

Finding, Development and Acquisition Costs, including FDC (1)(2)(3)(4)	2017	2016	2015
Company Gross			
Proved Producing			
Change in FDC ($ millions)	35.5	(95.9)	(63.4)
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	61.9	34.0	53.4
FD&A Costs ($/boe)	15.60	(5.07)	7.69
FD&A Recycle Ratio	1.0	(2.7)	2.2
FD&A Costs – Three-year Average ($/boe)	8.06	10.16	17.09
FD&A Recycle Ratio – Three-year Average	1.9	2.1	1.5
Total Proved			
Change in FDC ($ millions)	241.6	419.7	(589.5)
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	125.1	75.7	52.6
FD&A Costs ($/boe)	9.37	4.53	(2.20)
FD&A Recycle Ratio	1.7	3.0	(7.6)
FD&A Costs – Three-year Average ($/boe)	5.52	7.56	12.69
FD&A Recycle Ratio – Three-year Average	2.8	2.8	2.0
Proved plus Probable			
Change in FDC ($ millions)	459.4	25.0	(906.2)
Reserve Additions, including Net Acquisitions (Dispositions) (MMboe)	144.1	93.0	55.5
FD&A Costs ($/boe)	9.64	(0.55)	(7.80)
FD&A Recycle Ratio	1.7	(24.5)	(2.1)
FD&A Costs – Three-year Average ($/boe)	3.09	3.91	8.58
FD&A Recycle Ratio – Three-year Average	5.0	5.3	3.0

(1)	FD&A costs take into account reserves revisions during the year on a per boe basis.
(2)	The aggregate of the exploration and development costs incurred in the financial year and the changes during that year in estimated future development costs may not reflect the total F&D costs related to reserves additions for that year.
(3)	"Finding, development and acquisition recycle ratio" or "FD&A recycle ratio" does not have a standardized meaning. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" contained in this news release.
(4)	2015 and 2016 recycle ratios have been restated to reflect the exclusion of other income in operating netbacks.

NE BC MONTNEY RESOURCES EVALUATION

The following discussion in "NE BC Montney Resources Evaluation" is subject to a number of cautionary statements, assumptions and risks as set forth therein. See "Information Regarding Disclosure on Oil and Gas Reserves, Resources and Operational Information" at the end of this news release for additional cautionary language, explanations and discussion, and see "Forward-looking Information and Statements" for a statement of principal assumptions and risks that may apply. See also "Definitions of Oil and Gas Resources and Reserves" in this news release. The discussion includes reference to TPIIP, Discovered Petroleum Initially-in-Place ("DPIIP"), Undiscovered Petroleum Initially-in-Place ("UPIIP") and Economic Contingent Resource ("ECR") as per the GLJ Resources Evaluation as at December 31, 2017, prepared in accordance with the COGE Handbook. Unless otherwise indicated in this news release, all references to ECR and Prospective volumes are Best Estimate ECR and Best Estimate Prospective volumes, respectively.

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

GLJ was commissioned in 2017 and in 2016 to conduct independent resource evaluations for ARC's lands in the NE BC Montney region, including Dawson, Parkland/Tower, Sunrise/Sunset, Sundown, Septimus, Attachie, Red Creek and Blueberry in northeast British Columbia, and Pouce Coupe just across the provincial border in Alberta (the "Evaluated Areas"). The Independent Resources Evaluation was effective December 31, 2017 based on GLJ forecast pricing at January 1, 2018. The GLJ Independent Resources Evaluation conducted in respect of 2016 was effective December 31, 2016 based on GLJ forecast pricing at January 1, 2017 (the "2016 Resources Evaluation"). All references in the following discussion to TPIIP, DPIIP, UPIIP and ECR are in reference to the Evaluated Areas included in the 2017 Independent Resources Evaluation and 2016 Independent Resources Evaluation. The results of the 2017 and 2016 resources evaluations are summarized in the discussion and tables that follow.

The evaluation reaffirmed that ARC's NE BC Montney assets provide significant long-term growth opportunities with considerable resources, extending well beyond existing booked reserves and even the current estimates of ECR. ARC's NE BC Montney assets provide optionality for future growth through commodity price cycles given the diversity of ARC's Montney landholdings with exposure to liquids-rich natural gas, crude oil and dry natural gas. ARC believes that the concentrated nature of the assets will result in additional upside based on expected capital efficiencies.

ARC's 2017 capital development program was primarily focused on Montney development, which was inclusive of crude oil, liquids-rich gas and dry gas opportunities. In northeast British Columbia and Pouce Coupe, Alberta, ARC's capital development program consisted of drilling 87 gross operated wells (87 net wells), comprised of 29 tight oil wells at Tower, 37 wells at Dawson that were a combination of dry gas and liquids-rich wells, five dry gas wells at Sunrise, and 16 liquids-rich wells elsewhere in NE BC (nine in Attachie, six in Parkland, and one in Pouce Coupe).

TPIIP for the shale gas-bearing lands in the Evaluated Areas increased four per cent to 106.0 Tcf relative to 2016. DPIIP for the shale gas-bearing lands increased by nine per cent for the Evaluated Areas to 45.5 Tcf.

Shale gas ECR was evaluated on an unrisked and risked basis in 2017 and was subdivided into the Maturity Subclasses of Development Pending and Development Unclarified. The risked development pending shale gas ECR totaled 4.0 Tcf and risked development unclarified shale gas ECR totaled 3.1 Tcf. The risked prospective shale gas ECR totaled 6.4 Tcf.

NGLs ECR was evaluated on an unrisked and risked basis in 2017 and was subdivided into the Maturity Subclasses of Development Pending and Development Unclarified. The risked development pending NGLs ECR totaled 90 MMbbl and risked development unclarified NGLs ECR totaled 100 MMbbl. The risked prospective NGLs ECR totaled 475 MMbbl.

On the tight oil-bearing lands at Tower, Red Creek and Attachie, TPIIP remained consistent with 2016 at

10.5 MMbbl and DPIIP increased four per cent to 6.4 MMbbl.

Tight Oil ECR was evaluated on an unrisked and risked basis in 2017 and was subdivided into the Maturity Subclasses of Development Pending and Development Unclarified. The risked development pending tight oil ECR totaled 33 MMbbl and risked development unclarified tight oil ECR totaled 115 MMbbl. The risked prospective tight oil ECR totaled 76 MMbbl.

Risking of the economic contingent resources included a quantitative assessment of the economic status, the recovery technology status, the project evaluation scenario status, and the development time frame. Risking of the prospective resources included a quantitative assessment of these same factors, as wells as a quantitative assessment of the chance of discovery.

Table 8

Shale Gas Resources (1)(2)(3)(4)	2017	2016
(Tcf)		
Total Petroleum Initially-in-Place	106.0	101.5
Discovered Petroleum Initially-in-Place (5)	45.5	41.8
Undiscovered Petroleum Initially-in-Place (6)	60.5	59.7

(1)	TPIIP, DPIIP and UPIIP have been estimated using a one per cent porosity cut-off in both 2017 and 2016, which means that essentially all gas-bearing rock has been incorporated into the calculations.
(2)	The resource categories in this table do not include free crude oil or liquids.
(3)	All volumes listed in the table are company gross and raw gas volumes.
(4)	All numbers are "Best Estimates".
(5)	There is uncertainty that it will be commercially viable to produce any portion of the resources.
(6)	There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Table 9

Tight Oil Resources (1)(2)(3)(4)	2017	2016
(MMbbl)		
Total Petroleum Initially-in-Place	10,488	10,529
Discovered Petroleum Initially-in-Place (5)	6,427	6,180
Undiscovered Petroleum Initially-in-Place (6)	4,061	4,349

(1)	TPIIP, DPIIP and UPIIP have been estimated using a one per cent porosity cut-off in both 2017 and 2016 for tight oil.
(2)	All volumes listed in the table are company gross.
(3)	The tight oil DPIIP is a Stock Tank Barrel.
(4)	All numbers are "Best Estimates".
(5)	There is uncertainty that it will be commercially viable to produce any portion of the resources.
(6)	There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Table 10

	2017			2016		
Reserves and Risked and Unrisked ECR (1)(2)(3)(4)(5)(6)	Chance of Development	Best Estimate Unrisked	Best Estimate Risked	Chance of Development	Best Estimate Unrisked	Best Estimate Risked
Shale Gas (Tcf)						
Reserves	100%	3.5	3.5	100%	3.0	3.0
Development Pending ECR	86%	4.6	4.0	91%	2.9	2.6
Development Unclarified ECR	62%	4.2	3.1	74%	4.8	3.6
NGLs (MMbbl)						
Reserves	100%	62.1	62.1	100%	61.9	61.9
Development Pending ECR	85%	105.9	90.4	91%	58.6	53.5
Development Unclarified ECR	66%	139.8	100.3	74%	286.7	212.5
Tight Oil (MMbbl)						
Reserves	100%	31.2	31.2	100%	25.2	25.2
Development Pending ECR	92%	35.5	32.6	95%	42.0	39.9
Development Unclarified ECR	73%	156.9	114.5	69%	154.3	106.9

(1)	All DPIIP, other than cumulative production, reserves, and ECR, has been categorized as unrecoverable. Cumulative raw production to year-end 2017 was 0.9 Tcf of shale gas and 7.8 MMbbl of tight oil, all of which are immaterial in relation to the magnitude of the reserves and ECR. NGLs cumulative production is calculated based on current NGLs recoveries.
(2)	All volumes listed in the table are company gross and sales volumes.
(3)	All numbers are "Best Estimates".
(4)	All ECR have been risked for chance of development. For ECR, the chance of development is defined as the probability of a project being commercially viable. In quantifying the chance of development, factors that were assessed quantitatively to be less than one in the risking calculation included the economic status, the project evaluation scenario status, and the development time frame. The chance of development is multiplied by the unrisked resource volume estimate, which yields the risked volume estimate. As many of these factors have a wide range of uncertainty and are difficult to quantify, the chance of development is an uncertain value that should be used with caution.
(5)	For reserves, the volumes under the heading "Best Estimate" are 2P reserves.
(6)	There is uncertainty that it will be commercially viable to produce any portion of the resources.

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

Table 11

	2017			2016		
Risked and Unrisked ECR	Chance of	Best	Best	Chance of	Best	Best
Development Pending [1][2][3][4]	Development	Estimate	Estimate	Development	Estimate	Estimate
		Unrisked	Risked		Unrisked	Risked
Shale Gas (Tcf)	86%	4.6	4.0	91%	2.9	2.6
NGLs (MMbbl)	85%	105.9	90.4	91%	58.6	53.5
Tight Oil (MMbbl)	92%	35.5	32.6	95%	42.0	39.9
Oil Equivalent (MMboe)	86%	915.3	791.7	92%	577.3	528.9
Before-tax NPV ($ millions)						
Undiscounted		15,031	12,953		11,683	10,693
Discounted at 5%		5,417	4,675		4,431	4,068
Discounted at 10%		2,352	2,029		1,992	1,831
Discounted at 15%		1,153	993		1,006	925
Discounted at 20%		610	524		552	508
After-tax NPV ($ millions)						
Undiscounted		11,454	9,455		8,566	7,841
Discounted at 5%		4,183	3,313		3,185	2,924
Discounted at 10%		1,837	1,378		1,390	1,277
Discounted at 15%		908	635		675	620
Discounted at 20%		483	308		352	323

(1)	All volumes listed in the table are company gross and sales volumes.
(2)	2017 NPV as per GLJ Independent Resources Evaluation as of December 31, 2017 and based on GLJ forecast pricing at January 1, 2018. 2016 NPV as per GLJ Independent Resources Evaluation as of December 31, 2016 and based on GLJ forecast pricing at January 1, 2017.
(3)	Risk in the above table is the chance of development. Contingent resources are discovered resources by definition.
(4)	There is uncertainty that it will be commercially viable to produce any portion of the resources.

The estimated cost to bring on commercial production from the Development Pending Contingent Resources for all three product types is approximately $7.6 billion (when discounted at 10 per cent, the estimated cost is approximately $2.4 billion). The expected timeline to bring these resources on production is between two and 14 years. The ECR are expected to be recovered using the same technology of horizontal drilling and multi-stage fracturing that ARC has already proven to be effective in the Montney in northeast British Columbia.

Table 12

Prospective Resources (1)(2)(3)(4)(5)	2017 Chance of Commerciality	Best Estimate Unrisked	Best Estimate Risked	2016 Chance of Commerciality	Best Estimate Unrisked	Best Estimate Risked
Shale Gas (Tcf)	46%	13.7	6.4	48%	14.7	7.0
NGLs (MMbbl)	43%	1,117.0	474.8	45%	1,042.1	471.5
Tight Oil (MMbbl)	63%	120.3	76.1	41%	122.5	49.9
Oil Equivalent (MMboe)	46%	3,528.2	1,615.4	47%	3,612.1	1,686.6

(1)	All UPIIP, other than prospective resources, has been categorized as unrecoverable.
(2)	All volumes listed in the table are company gross and sales volumes.
(3)	Prospective resources have been risked for chance of development and chance of discovery. For prospective resources, the chance of development multiplied by the chance of discovery is defined as the probability of a project being commercially viable. In quantifying the chance of commerciality, factors that were assessed quantitatively to be less than one in the risking calculation included the economic status, the project evaluation scenario status and the development time frame, along with the overall chance of discovery. The chance of commerciality is multiplied by the unrisked prospective resource volume estimate, which yields the risked volume estimate. As many of these factors have a wide range of uncertainty and are difficult to quantify, the chance of commerciality is an uncertain value that should be used with caution.
(4)	All prospective resources are subclassified as the prospect maturity subclass.
(5)	There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Based upon the foregoing analysis, as well as ARC's expertise in the Montney formation in northeast British Columbia, it is expected that significant additional reserves will be developed in the future with continued drilling success on currently undeveloped Montney acreage, together with further development, completions refinements and improved economic conditions. Historic drilling success and recoveries on the more fully-developed Montney acreage, abundant well log and production test data, and the application of increased drilling densities, support ARC's belief that significant additional resources will be recovered. Continuous development through multi-year exploration and development programs and significant levels of future capital expenditures are required in order for additional resources to be recovered in the future. The principal risks that would inhibit the recovery of additional reserves relate to the potential for variations in the quality of the Montney formation where minimal well data currently exists, access to the capital which would be required to develop the resources, low commodity prices that would curtail the economics of development and the future performance of wells, regulatory approvals, access to the required services at the appropriate cost, and the effectiveness of well fracturing technology and applications. For ECR to be converted to reserves, Management and the Board of Directors need to ascertain commercial production rates, then develop firm plans, including timing, infrastructure, and the commitment of capital. Confirmation of commercial productivity is generally required before the Company can prepare firm development plans and commit required capital for the development of the ECR. Additional contingencies are related to the current lack of infrastructure required to develop the resources in a relatively quick time frame. As continued delineation occurs, some resources currently classified as ECR are expected to be re-classified to reserves.

DEFINITIONS OF OIL AND GAS RESOURCES AND RESERVES

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates as follows:

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.

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.

Resources encompasses all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including Discovered and Undiscovered (recoverable and unrecoverable) plus quantities already produced. "Total Resources" is equivalent to "Total Petroleum Initially-in-Place". Resources are classified in the following categories:

Total Petroleum Initially-in-Place ("TPIIP") is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.

Discovered Petroleum Initially-in-Place ("DPIIP") is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of DPIIP includes production, reserves, and contingent resources; the remainder is unrecoverable.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development but which are not currently considered to be commercially recoverable due to one or more contingencies.

Economic Contingent Resources ("ECR") are those Contingent Resources which are currently economically recoverable.

Project Maturity Subclass Development Not Viable is defined as a Contingent Resource that is not viable in the conditions prevailing at the effective date of the evaluation, and where no further data acquisition or evaluation is planned and therefore has not been assigned a low chance of development.

Project Maturity Subclass Development Pending is defined as a Contingent Resource that has been assigned a high chance of development and the resolution of final conditions for development are being actively pursued.

Project Maturity Subclass Development Unclarified is defined as a Contingent Resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined.

Undiscovered Petroleum Initially-in-Place ("UPIIP") is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of UPIIP is referred to as "prospective resources" and the remainder as "unrecoverable".

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

Unrecoverable is that portion of DPIIP and UPIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Uncertainty Ranges are described by the COGE Handbook as low, best, and high estimates for reserves and resources. The Best Estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 per cent probability that the quantities actually recovered will equal or exceed the best estimate.

INFORMATION REGARDING DISCLOSURE ON OIL AND GAS RESERVES, RESOURCES AND OPERATIONAL INFORMATION

All amounts in this news release are stated in Canadian dollars unless otherwise specified. Where applicable, natural gas has been converted to barrels of oil equivalent ("boe") based on a six Mcf to one barrel ratio. The boe rate is based on an energy equivalency conversion method primarily applicable at the burner tip, and given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value. The boe rate is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of boe in isolation may be misleading. In accordance with Canadian practice, production volumes and revenues are reported on a company gross basis, before deduction of Crown and other royalties, and without including any royalty interest, unless otherwise stated. Unless otherwise specified, all reserves volumes in this news release (and all information derived therefrom) are based on company gross reserves using forecast prices and costs.

This news release contains metrics commonly used in the oil and natural gas industry. Each of these metrics is determined by ARC as set out below. These metrics are "reserve replacement", "reserve life index", "recycle ratio", "finding and development costs", "finding, development and acquisition costs", "operating netbacks", "finding and development recycle ratio", and "finding, development and acquisition recycle ratio". These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies. As such, they should not be used to make comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare ARC's performance over time, however, such measures are not reliable indicators of ARC's future performance and future performance may not compare to the performance in previous periods.

- "Reserve replacement" is calculated by dividing the annual 2P reserve additions (in boe) by ARC's annual produc Management uses this measure to determine the relative change of its reserves base over a period of time.
- "Reserve life index" or "RLI" is calculated by dividing the reserves (in boe) in the referenced category by the midp guidance (in boe) for the following year. Management uses this measure to determine how long the booked reser current production rates if no further reserves were added.
- "Recycle ratio" is calculated by dividing the operating netback for the year (in dollars per boe) by FD&A costs for t dollars per boe).
- "Finding and development costs" or "F&D costs" are calculated by dividing the sum of the total capital expenditure dollars) by the change in reserves within the applicable reserves category (in boe). F&D costs, including FDC, inc expenditures in the year as well as the change in FDC required to bring the reserves within the specified reserves production.
- "Finding, development and acquisition costs" or "FD&A costs" are calculated by dividing the sum of the total capit for the year inclusive of the net acquisition costs and disposition proceeds (in dollars) by the change in reserves w applicable reserves category inclusive of changes due to acquisitions and dispositions (in boe). FD&A costs, inclu includes all capital expenditures in the year inclusive of the net acquisition costs and disposition proceeds as well FDC required to bring the reserves within the specified reserves category on production.

-
  - Both F&D and FD&A costs take into account reserves revisions and capital revisions during the year. The a costs incurred in the financial year and changes during that year in estimated FDC may not reflect total F&D reserves additions for that year. F&D costs and FD&A costs have been presented in this news release beca and dispositions can have a significant impact on ARC's ongoing reserves replacement costs and excluding could result in an inaccurate portrayal of its cost structure. Management uses F&D and FD&A as measures execute its capital programs (and success in doing so) and of its asset quality.
- "Operating netback" is calculated using production revenues, excluding realized gains and losses on commodity r contracts, less royalties, transportation and operating expenses, calculated on a per boe equivalent basis. Manag measure to benchmark operating results between areas and/or time periods.
- "Finding and development recycle ratio" or "F&D recycle ratio" is calculated by dividing the operating netback (in d by the F&D costs (in dollars per boe) for the year.
- "Finding, development and acquisition recycle ratio" or "FD&A recycle ratio" is calculated by dividing the operating dollars per boe) by the FD&A costs (in dollars per boe) for the year.
-
  - ARC uses both F&D recycle ratio and FD&A recycle ratio as an indicator of profitability of its oil and gas act

ARC's oil and gas reserves statement for the year ended December 31, 2017, which will include complete disclosure of its oil and gas reserves and other oil and gas information in accordance with NI 51-101, will be contained within ARC's AIF which will be available on or before March 30, 2018 on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

This news release contains references to estimates of resources other than reserves in the Montney region in northeast British Columbia, including lands in Pouce Coupe in Alberta, which are not, and should not be confused with, oil and gas reserves. See "Definitions of Oil and Gas Resources and Reserves".

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

ARC's belief that it will establish significant additional reserves over time with conversion of DPIIP into ECR, ECR into 2P reserves, and probable reserves into proved reserves, is a forward-looking statement and is based on certain assumptions and is subject to certain risks, as discussed below under the heading "Forward-looking Information and Statements".

Notice to US Readers

The oil and natural gas reserves contained in this news release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects of United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission ("the SEC") generally permits oil and gas issuers, in their filings with the SEC, to disclose only proved reserves (as defined in SEC rules). Canadian securities laws require oil and gas issuers, in their filings with Canadian securities regulators, to disclose not only proved reserves (which are defined differently from the SEC rules) but also probable reserves, each as defined in NI 51-101. Accordingly, proved reserves disclosed in this news release may not be comparable to US standards, and in this news release, ARC has disclosed reserves designated as "probable reserves" and "proved plus probable reserves". Probable reserves are higher-risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. The SEC's guidelines strictly prohibit reserves in these categories from being included in filings with the SEC that are required to be prepared in accordance with US disclosure requirements. In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalties and similar payments. The practice in the United States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. Moreover, ARC has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC generally requires that prices and costs be held constant at levels in effect at the date of the reserve report. As a consequence of the foregoing, ARC's reserve estimates and production volumes in this news release may not be comparable to those made by companies utilizing US reporting and disclosure standards. Additionally, the SEC prohibits disclosure of oil and gas resources, whereas Canadian issuers may disclose resource volumes. Resources are different than, and should not be construed as, reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, resources, see above.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect," "anticipate," "continue," "estimate," "objective," "ongoing," "may," "will," "project," "should," "believe," "plans," "intends," "strategy," and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the recognition of significant additional reserves under the heading "2017 Independent Reserves Evaluation" and the recognition of significant resources under the heading "NE BC Montney Resources Evaluation", the volumes and estimated value of ARC's oil and gas reserves; the future net value of ARC's reserves; the future development costs; the future abandonment and reclamation costs; the 2018 capital expenditure budget, the life of ARC's reserves; the volume and product mix of ARC's oil and gas production; future oil and natural gas prices; future results from operations and operating metrics; and future development, exploration, acquisition and development activities (including drilling plans) and related production expectations.

The forward-looking information and statements contained in this news release reflect several material factors and expectations and assumptions of ARC including, without limitation: that ARC will continue to conduct its operations in a manner consistent with past operations; results from drilling and development activities are consistent with past results; the continued and timely development of infrastructure in areas of new production; the general continuance of current industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; the accuracy of the estimates of ARC's reserve and resource volumes; certain commodity price and other cost assumptions; and the continued availability of adequate debt and equity financing and cash flow to fund its planned expenditures. There are a number of assumptions associated with the development of the Evaluated Areas, including the quality of the Montney reservoir, continued performance from existing wells, future drilling programs and performance from new wells, the growth of infrastructure, well density per section, and recovery factors and development necessary involves known and unknown risks and uncertainties, including those risks identified in this news release. ARC believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and 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 information or statements including, without limitation: changes in commodity prices; the early stage of development of some areas in the Evaluated Areas; the potential for variation in the quality of the Montney formation, changes in the demand for or supply of ARC's products; unanticipated operating results or production declines; unanticipated results from ARC's exploration and development activities; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of ARC or by third-party operators of ARC's properties, increased debt levels or debt service requirements; inaccurate estimation of ARC's oil and gas reserve and resource volumes; limited, unfavorable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time to time in ARC's public disclosure documents (including, without limitation, those risks identified in this news release and in ARC's AIF).

The forward-looking information and statements contained in this news release speak only as of the date of this news release, and none of ARC or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

ARC Resources Ltd. is one of Canada's largest conventional oil and gas companies with an enterprise value [(1)] of approximately $5.2 billion. ARC's common shares trade on the TSX under the symbol ARX.

ARC Resources Ltd.

Myron M. Stadnyk
President and Chief Executive Officer

(1)	Enterprise value is also referred to as total capitalization. Refer to Note 16 "Capital Management" in ARC's financial statements for the three months and year ended December 31, 2017 and to the section entitled "Capitalization, Financial Resources and Liquidity" contained within ARC's MD&A.

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Contact
about ARC Resources Ltd., please visit our website www.arcresources.com or contact: Investor Relations, E-mail: ir@arcresources.com, Telephone: (403) 503-8600, Fax: (403) 509-6427, Toll Free: 1-888-272-4900, ARC Resources Ltd., Suite 1200, 308 - 4th Avenue SW, Calgary, AB T2P 0H7

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