FORM 51-101F1
STATEMENT OF RESERVES DATA AND
OTHER OIL AND GAS INFORMATION

This Statement of Reserves Data and other Oil and Gas Information for Canadian Spirit Resources Inc. ("CSRI" or the "Corporation") is dated April 25, 2018. The effective date of the information provided in this statement is December 31, 2017 unless otherwise indicated. The information was prepared between December 31, 2017 and April 25, 2018.

GLJ Petroleum Consultants Ltd. ("GLJ") was engaged to prepare an independent reserve assessment on the Corporation's lands as at December 31, 2017 in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("GLJ Reserve Report").

The GLJ Reserve Report also presents the estimated net present value of future net revenue before taxes, at various discount rates. Assumptions and qualifications relating to costs and prices for future production and other matters are summarized in the notes to the following tables.

The extent and nature of all information supplied by CSRI which may have included ownership data, well information, geological information, reservoir studies, timing and future production, gas sales contract information, current product prices, operating cost data, capital budget forecasts and future operating plans, have been relied upon by GLJ in preparing the GLJ Reserve Report and were accepted as represented without independent verification. In the absence of such information, GLJ relied, with the approval of CSRI, upon its opinion of reasonable practice in the industry. All information provided to GLJ was as at December 31, 2017 and accordingly, some of such information may not be representative of current conditions.

The definitions of the various categories of reserves and expenditures are those set out in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl 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 from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

It should not be assumed that the present worth of estimated future net revenue represents the fair market value of the reserves. There is no assurance that the escalating price and cost assumptions contained in the GLJ Reserve Report will be attained and variances could be material. The reserve and revenue estimates set forth below are estimates only and the actual reserves and realized revenue may be greater or less than those calculated.

Reserves Data – Forecast Prices and Costs

The following table discloses the Corporation's gross and net proved reserves and proved plus probable reserves, estimated using forecast prices and costs.

SUMMARY OF RESERVES AS AT DECEMBER 31, 2017
(Forecast Prices & Costs) (4)

	Shale Gas (1)		Barrels of Oil Equivalent	
	Gross (2) (MMcf)	Net (3) (MMcf)	Gross (2) (Mboe)	Net (3) (Mboe)
PROVED				
Developed Producing	1,550	1,506	258	251
Total Proved	1,550	1,506	258	251
PROBABLE	8,756	8,228	1,459	1,371
TOTAL PROVED PLUS PROBABLE	10,306	9,734	1,718	1,622

Notes:
(1) "Shale Gas" means natural gas contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily absorbed on the kerogen or clay minerals, and that usually requires the use of hydraulic fracturing to achieve economic production rates.
(2) "Gross Reserves" are the Corporation's working interest share of the remaining reserves, before deduction of any royalties.
(3) "Net Reserves" are the Corporation's working interest share of remaining reserves less all Crown royalties.
(4) May not add due to rounding.

The following table summarizes the net present value of the Corporation's reserves based on the GLJ future price forecast as at December 31, 2017.

SUMMARY OF NET PRESENT VALUES AS AT DECEMBER 31, 2017

Discounted at					
($ Thousands) (1)	0%	5%	10%	15%	20%
PROVED					
Developed Producing	225	249	233	207	181
Total Proved	225	249	233	207	181
PROBABLE	11,784	4,351	1,520	915	-251
TOTAL PROVED PLUS PROBABLE	12,009	4,601	1,753	512	-70

Note:
(1) May not add due to rounding.

The following two tables provide additional information regarding the future net revenue attributable to total proved reserves and total proved plus probable reserves.

The following table discloses, in the aggregate, certain elements of the Corporation's future net revenue attributable to its proved reserves and its proved plus probable reserves, estimated using forecast prices and costs, and calculated without discount. All properties are located in Canada.

TOTAL FUTURE NET REVENUE (Undiscounted)
AS AT DECEMBER 31, 2017
(Forecast Prices & Costs) ($ Thousands)

RESERVE CATEGORY	Sales Revenue	Royalties	Operating Costs	Development Costs	Abandon-ment Costs and Reclamation	BT Future Net Revenue (1) (2) (3)
PROVED	4,798	137	3,985	179	272	225
PROVED PLUS PROBABLE	40,876	2,328	15,230	10,642	577	12,099

Notes:
(1) BT = Before Taxes.
(2) May not add due to rounding.
(3) After Taxes = Before Taxes.

The following table discloses, by production group, the net present value of the Corporation's future net revenue attributable to its proved reserves and its proved plus probable reserves, before deducting future income tax expenses, estimated using forecast prices and costs, and calculated using a 10% discount rate.

NET PRESENT VALUE OF FUTURE NET REVENUE
BY PRODUCTION GROUP AS AT DECEMBER 31, 2017
(Forecast Prices & Costs)

RESERVE CATEGORY	PRODUCTION GROUP	Future Net Revenue BT Discounted (10%/Yr.) $ Thousands (1)	Unit Value BT Discounted (10%/Yr.) $/boe (1) (2)
PROVED	Shale Gas	233	0.93
PROVED PLUS PROBABLE	Shale Gas	1,753	1.08

Notes:
(1) BT = Before Taxes.
(2) Calculated as the Net Present Value before income taxes discounted at 10% per year divided by the net reserves volume.

Forecast Prices used in Estimates

The forecast reference prices used by GLJ in preparing the Corporation's reserves data are provided in the table below.

SUMMARY OF PRICING, INFLATION RATE AND EXCHANGE RATE ASSUMPTIONS AS AT DECEMBER 31, 2017

FORECAST YEAR	WTI CUSHING OKLAHOMA ($US/bbl)	HENRY HUB ($US/MMBtu)	B.C. WESTCOAST STATION 2 ($Cdn/MMBtu)	INFLATION RATE (%/Yr.)	EXCHANGE RATE ($US/$Cdn.)
2018	59.00	3.20	2.70	2	0.775
2019	64.00	3.40	2.97	2	0.800
2020	67.00	3.60	3.19	2	0.825
2021	71.00	3.80	3.37	2	0.850
2022	74.00	4.00	3.56	2	0.850
2023	77.00	4.20	3.75	2	0.850
2024	80.00	4.31	3.86	2	0.850
2025	83.00	4.39	3.94	2	0.850
2026	86.05	4.48	4.02	2	0.850
2027					

Escalation rate of 2.0% thereafter

*The Corporation's weighted average price received for natural gas in 2017 was $2.04 $Cdn/MMBtu.

Reserves Reconciliation

The GLJ Reserve Report represents the Corporation's reserves data as at December 31, 2017. The reconciliation of changes in reserves is based on the previous year end occurring as at December 31, 2016.

RECONCILIATION OF COMPANY GROSS RESERVES

FACTORS	Shale Gas			BOE		
	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2016	1,296	8,410	9,706	216	1,402	1,618
Discoveries	0	0	0	0	0	0
Extensions*	0	0	0	0	0	0
Infill Drilling*	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0
Technical Revisions	487	346	833	81	58	139
Acquisitions	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0
Production	(233)	0	(233)	(39)	0	(39)
December 31, 2016	1,550	8,756	10,306	258	1,460	1,718

* The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as "Extensions and Improved Recovery".

Changes to reserves between the current and the previous reporting periods are due to a number of factors. Technical revisions occurred due to the increase in natural gas shrinkage at the Company's production facility along with increased decline rates as a result of the six-month shut-in of producing wells in 2017. These two technical factors combine to cause the property to reach its economic limit sooner resulting in a loss of reserves. Economic adjustments are the result of changes in long term price forecasts, inflation rates and regulatory changes. Production adjustments are the result of the natural depletion of reserves.

Undeveloped Reserves

The following table disclosed the Corporation's gross proved and probable undeveloped reserves in which the Corporation has a working interest position. The Corporation has plans for developing most of the proved undeveloped and the probable undeveloped reserves within the next five years. Timing of drilling will be dependent on an increase in natural gas prices above their current level.

UNDEVELOPED RESERVES ATTRIBUTED IN CURRENT YEAR 2017

PROVED UNDEVELOPED RESERVES

Shale Gas (MMcf)		BOE (MMbl)	
First Attributed	Total at Year-end	First Attributed	Total at Year-end
0	0	0	0

PROBABLE UNDEVELOPED RESERVES

	Shale Gas (MMcf)		Oil Equivalent (MMbl)	
	First Attributed*	Total at Year-end	First Attributed	Total at Year-end
2015	0	8,152	0	1,359
2016	0	7,921	0	1,320
2017	0		0	

*"First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

**Note: Prior to 2016 Shale Gas was classified as Conventional Natural Gas.

Significant Factors or Uncertainties Affecting Reserves Data

Estimates of economically recoverable oil and natural gas reserves and the associated future net cash flows are based upon a number of variable factors and assumptions. The main area of uncertainty is commodity prices, as the Corporation currently sells all production at spot market pricing and has no hedges presently in place.

The process of estimating oil and gas reserves is complex, requiring significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas processing and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions, and are evaluated by an independent engineering firm. As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in period end gas prices and reservoir performance. Such revisions can be either positive or negative. The reserve estimates of the Corporation's natural gas reserves produced in this document are estimates only. There is no assurance or guarantee that the estimated reserves will be recovered. Actual reserves may be greater or less than the estimates provided herein.

Future Development Costs

The following table provides information regarding the development costs deducted in the estimation of future net revenue attributable to the Corporation's reserves.

FUTURE DEVELOPMENT COSTS
(Forecast Prices & Costs) ($ Thousands) (1) (2)

Year	For Proved Reserves	For Proved Plus Probable Reserves
2018	0	0
2019	0	0
2020	0	0
2021	0	0
2022	0	10,456
THEREAFTER	179	186
TOTAL UNDISCOUNTED	179	10,642

Notes:
(1) Future Development Costs shown are associated with booked reserves in the GLJ Reserve Report and do not necessarily represent the Corporation's full exploration and development budget.
(2) May not add due to rounding.

The Corporation expects that the funds required for future development costs will be obtained from the combination of positive working capital, internally-generated cash flow, credit facilities and equity financing. There can be no guarantee that funds will be available or that the Corporation will allocate funding to develop all of the reserves attributed in the GLJ Reserve Report. Failure to develop those reserves would have a negative impact on future cash flow.

Interest and other costs of external funding are not included in the future development costs of the reserves or in the future net revenue estimates, and would reduce reserves and future net revenue to some degree depending upon the funding source utilized. The Corporation does not anticipate that interest or other funding costs would make development of any property uneconomic.

Oil and Gas Properties and Wells

CSRI's core area of activity is in the Farrell Creek/Altares area of northeastern British Columbia approximately 15 km north of the town of Hudson's Hope.

The Corporation has focused on two primary objectives in this core area:

- The Cretaceous Gething Formation coals and tight sands; and
- The Triassic Montney Formation shale gas.

a) Gething

The Gething coals and tight sand pilot project resulted in the drilling of 14 wells including 13 potential producing wells and one water disposal well. Seven wells were completed, equipped and tied into the 100% owned CSRI gas plant. The plant has an initial processing capacity of 1.25 MMcf/day of natural gas and is pipeline connected to the Spectra Energy mainline. The pilot project was suspended in 2010 and the producing wells and gas plant are currently shut in. Of the remaining seven wells that were drilled, six are cased and suspended and one has been abandoned. No reserves have been attributed to the Gething project.

b) Montney

The Montney shale gas project has 13 wells drilled with 10 (net 3.25) drilled on joint venture ("JV") lands and three on 100% CSRI lands. The five JV wells that were on production as at December 31, 2017 through the joint venture gas plant (CSRI 35%) are pipeline connected to the Spectra Energy mainline. The JV plant has a processing capacity of 10 MMcf/day of natural gas. Of the remaining eight wells that were drilled, six are cased and suspended, one has been abandoned, and one is standing cased waiting on abandonment.

Properties with No Attributed Reserves
The Corporation's unproved properties are comprised of 14,435 gross (8,935 net) hectares of Montney Formation rights and 14,641 gross (14,510 net) hectares of Gething Formation rights located in British Columbia, Canada, none of which have any work commitments.

The presence of economic quantities of hydrocarbons on lands with no attributed reserves is uncertain until drilled and tested. Beyond the need to drill and test exploration areas, additional factors may influence the Corporation's ability to develop these lands, including escalation of capital costs and operating costs, the potential requirement to expand existing infrastructure and a material drop in commodities prices.

Forward Contracts
As at December 31, 2017, the Corporation had not entered into any forward contracts, transportation agreements or other future obligations.

Tax Horizon
Based on after tax economic forecasts prepared by GLJ, income taxes are not payable in the foreseeable future by the Corporation.

Costs Incurred
During 2017, the Corporation incurred $0.2 million of acquisition and retention costs for unproved properties and $3.4 million (net) of exploration and $Nil development costs in western Canada.

Exploration and Development Activities
During 2016, the Corporation drilled the c-69-H/94-B-1 location on the western block of its Farrell Creek area. This 100% vertical test well was drilled to a final total depth of 2,762 meters to evaluate the Montney potential of this area and for land retention purposes. At December 31, 2017, this well was standing cased waiting on abandonment.

For the twelve month period ended December 31, 2017, net capital expenditures totaled $3.9 million (2016: $0.8 million), compared to an allocated budgeted capital expenditure of $3.6 million (2015: $0.6 million). For the twelve months ended December 31, 2017, the main component of the drilling, completion and facilities total of $3.4 million were the costs related to the abandonment of the c-69-H/94-B-1 well.

CSRI's capital budget is approved on an annual basis, and subsequently reviewed quarterly, by the Corporation's Board of Directors. The Board of Directors has approved a base capital expenditure budget for 2018 of $0.6 million (net), primarily for lease rental and maintenance capital, but also including an estimated $0.3 million for capitalized overhead.

CSRI has budgeted for cash administration expenses (general and administrative expenses excluding share-based compensation) for 2018 to total $1.1 million (2017: $1.3 million), before capitalization of exploration and development related overhead, and has budgeted for operating netbacks from the Farrell Creek/Altares Montney operations for 2018 of $0.2 million (2017: $0.1 million).

Production Estimates

The following table summarizes the Corporation's estimated future average daily production volumes for 2018, as provided by the GLJ Reserve Report.

SUMMARY OF FIRST YEAR PRODUCTION AND OIL AND GAS RESERVES

	2018 Average Daily Production		Reserves			
	Shale Gas		Shale Gas		Oil Equivalent	
	Company Gross (Mcf/d)	Company Net (Mcf/d)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (Mboe)	Company Net (Mboe)
Proved Producing	567	550	1,550	1,506	258	251
Proved Developed Nonproducing	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0
Total Proved	567	550	1,550	1,506	258	251
Total Probable	6	6	8,756	8,228	1,459	1,371
Total Proved Plus Probable	573	556	10,306	9,734	1,718	1,622

Production History

The following table summarizes the Corporation's average gross daily production volumes for the financial year ended December 31, 2016.

PRODUCTION HISTORY YEAR ENDED DECEMBER 31, 2017

Shale Gas (MMcf/d)		Average Per Unit of Volume ($/Mcf) Production			
Yearly Quarter	Production Volume (1)	Price	Royalties (2)	Costs (3)	Netbacks
1st Quarter	0.64	1.41	0.01	1.80	(0.39)
2nd Quarter	N/A	N/A	N/A	N/A	N/A
3rd Quarter	N/A	N/A	N/A	N/A	N/A
4th Quarter	1.10	2.37	0.03	0.49	1.88

Notes:

(1) Production volumes reflect the Corporation's share of average daily production volume, before deduction of royalties.

(2) Royalties exclude prior period adjustments and credits.

(3) Production costs include transportation costs and production operating costs.