Canacol Energy Ltd. Achieves 169% 2P Reserve Replacement Ratio Increasing 2P Reserves to 652 Bcfe with a Before Tax Value of US$1.9 Billion

CALGARY, ALBERTA - (March 21, 2023) - Canacol Energy Ltd. ("Canacol" or the "Corporation") (TSX:CNE; OTCQX:CNNEF; BVC:CNEC) is pleased to report its conventional natural gas and light/medium crude oil reserves for the fiscal year end December 31, 2022. The Corporation's conventional natural gas reserves are located in the Lower Magdalena Valley basin, Colombia. Newly discovered light/medium crude oil reserves are located in the Middle Magdalena Valley basin, Colombia.

Canacol Energy Ltd Gross Conventional Natural Gas and Light/Medium Crude Oil Reserves Summary(1)(5)

Product Type		Proved Developed Producing *("PDP")*	Total Proved *("1P")*	Total Proved + Probable *("2P")*	Total Proved + Probable + Possible *("3P")*
Conventional natural gas and light/medium crude oil(4)	***Bcfe(2)***	**161.6**	**339.2**	**652.5**	**1088.2**
Total oil equivalent	*MMBOE(2)*	28.4	59.5	114.5	190.9
Before tax NPV-10(3)	*MM US$*	$479.1	$993.4	$1,937.3	$3,142.3
After tax NPV-10(3)	*MM US$*	$466.1	$775.6	$1,318.7	$2,010.7

(1) All reserves are represented at Canacol's working interest share before royalties.
(2) The term "BOE" means a barrel of oil equivalent and the term "cfe" means cubic feet equivalent of natural gas on the basis of 5.7 thousand standard cubic feet ("Mcf") of natural gas to 1 barrel of oil ("bbl") as per Colombian regulatory practice.
(3) Net Present Value (NPV) is stated in millions of USD and is discounted at 10 percent.
(4) Conventional natural gas represents 100% of PDP, 98.3% of 1P, 95.0% of 2P, and 92.9% of 3P volumes with conventional light/medium oil being the remainder.
(5) The numbers in this table may not add due to rounding.

Highlights

Conventional Natural Gas and Light/Medium Crude Oil Proved + Probable Reserves ("2P"):

- Increased by 7.5% since December 31, 2021, totaling 652 billion standard cubic feet equivalent ("Bcfe") at December 31, 2022, with a before tax value discounted at 10% of US$1.9 billion, representing both CAD$76.67 per share of reserve value, and CAD$53.79 per share of 2P net asset value (net of US$578.2 million of net debt)
- Reserve replacement of 169% based on calendar 2022 conventional natural gas and light/medium crude oil reserve additions of 79.5 Bcf and 5.7 MMBbls, respectively, totaling 112 Bcfe
- 2P Finding and Development Cost ("F&D") of US$1.87 / Mcfe for the three-year period ending December 31, 2022
- Recycle ratio of 1.7x for the year ended December 31, 2022 (calculated based on the natural gas netback of US$3.68 / Mcf for the year ended December 31, 2022)
- Recycle ratio of 1.9x for the three-year period ending December 31, 2022 (calculated based on the weighted average natural gas netback of US$3.55 / Mcf for the years ended December 31, 2022, 2021 and 2020)
- Reserves life index ("RLI") of 10.0 years based on annualized fourth quarter 2022 conventional natural gas production of 177,985 thousand standard cubic feet per day ("Mscfpd") or 31,225 barrels of oil equivalent per day ("BOEPD")
- RLI of 8.7 years based on conventional natural gas production guidance of 206,000 Mcfpd for calendar 2023 (high end 2023 production guidance as announced December 20, 2022)

Conventional Natural Gas and Light/Medium Crude Oil Total Proved Reserves ("1P"):

- Decreased by 7.9% since December 31, 2021, totaling 339 Bcfe at December 31, 2022, with a before tax value discounted at 10% of US$1.0 billion, representing both CAD$39.32 per share of reserve value, and CAD$16.43 per share of 1P net asset value (net of US$578.2 million of net debt)
- Reserve replacement of 56% based on calendar 2022 conventional natural gas and light/medium crude oil reserve additions of 31.5 Bcf and 1.0 MMBbls, respectively, totaling 37 Bcfe
- Concurrent drilling operations through to year end resulted in discoveries at Chimela on the VMM45 block, Saxofon on the VIM5 block, and Dividivi on the VIM33 block. However, by the December 31, 2022 effective date of the report, limited production testing could occur impacting 1P reserve bookings.
- 1P F&D of US$2.60 / Mcfe for the three-year period ending December 31, 2022
- RLI of 5.2 years based on annualized fourth quarter 2022 conventional natural gas production of 177,985 Mcfpd or 31,225 BOEPD
- RLI of 4.5 years based on conventional natural gas production guidance of 206,000 Mcfpd for calendar 2023 (high end 2023 production guidance as announced December 20, 2022)

Conventional Natural Gas and Light/Medium Crude Oil Total Proved + Probable + Possible Reserves ("3P"):

- Increased by 14.3% since December 31, 2021, totaling 1,088 Bcfe at December 31, 2022, with a before tax value discounted at 10% of US$3.1 billion, representing both CAD$124.36 per share of reserve value, and CAD$101.48 per share of 3P net asset value (net of US$578.2 million of net debt)
- Reserve replacement of 304% based on calendar 2022 conventional natural gas and light/medium crude oil reserve additions of 124.8 Bcf and 13.6 MMBbls, respectively, totaling 202 Bcfe.
- 3P F&D of US$1.05 / Mcf for the three-year period ending December 31, 2022
- RLI of 16.8 years based on annualized fourth quarter 2022 conventional natural gas production of 177,985 Mcfpd or 31,225 BOEPD
- RLI of 14.5 years based on conventional natural gas production guidance of 206,000 Mcfpd for calendar 2023 (high end 2023 production guidance as announced December 20, 2022)

Ravi Sharma, COO said "We are pleased to report our 2022 year-end reserves. We achieved a 2P Reserve Replacement Ratio of 169%, demonstrating organic growth in both our traditional core area in the Lower Magdalena Valley Basin and a new area of focus in the Middle Magdalena Valley Basin. Over the past decade, we have added more than 880 BCF of 2P conventional natural gas reserves from success in 35 out of 41 drilled exploration wells resulting in a 22% Compound Annual Growth Rate ("CAGR") in 2P conventional natural gas reserves. With our exploration focused drilling campaign in 2023 and a portfolio of 178 identified prospects and leads containing mean unrisked prospective conventional natural gas resources of 20.5 trillion cubic feet, according to our 2021 third party resource report, we anticipate many more years of successful exploration drilling. Our 2023 work program will also test, appraise and tie in recent discoveries, and bring multiple currently non-producing wells back into production."

Discussion of Year Ended December 31, 2022 Reserves Report

During the year ended December 31, 2022, the Corporation recorded increases in certain reserve categories due to discoveries at Alboka, Claxon, Saxofon, and Manchego on the VIM5 block, Canaflecha-2 on the Esperanza block, Carambolo and Cornamusa on the VIM21 block, Chimela (oil) on the VMM45 block, Dividivi on the VIM33 block, and Chinu on the SSJN7 block. All aforementioned additions are in the Lower Magdalena Valley basin except Chimela, which is in the Middle Magdalena Valley basin. Positive technical revisions were associated primarily with Clarinete, Pandereta, and Siku on the VIM5 block, San Marcos on the Esperanza block, and Aguas Vivas on the VIM21 block. Negative technical revisions were associated primarily with Chirimia on the VIM5 block and Toronja on the VIM21 block.

The following tables summarize information from the independent reserves report prepared by Boury Global Energy Consultants Ltd. ("BGEC") effective December 31, 2022 (the "BGEC 2022 report"). The BGEC 2022 report covers 100% of the Corporation's conventional natural gas and light/medium oil reserves.

CANACOL ENERGY LTD.

The BGEC 2022 report was prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument NI 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional reserve information as required under NI 51-101 is included in the Corporation's Annual Information Form, which will be filed on SEDAR by March 31, 2023.

Canacol Gross Natural Gas and Light/Medium Crude Oil Reserves for the Year Ended December 31, 2022[1]

Reserve Category[2]	31-Dec-21 (MMcfe)	31-Dec-22 (MMcfe)	Difference (%)
Proved Developed Producing (PDP)	236,023	161,633	-31.5%
Total Proved (1P)	368,366	339,243	-7.9%
Total Proved + Probable (2P)	**606,855**	**652,466**	**7.5%**
Total Proved + Probable + Possible (3P)	952,292	1,088,172	14.3%

(1) The numbers in this table may not add due to rounding.
(2) All reserves are Canacol working interest before royalties.

5-Year Gas and Oil Price Forecasts – BGEC Report December 31, 2022[1]

		Reserve Report Date	2023	2024	2025	2026	2027
Volume weighted Total Proved + Probable (2P) average gas price[2]	*US$/Mcf*	31-Dec-22	5.00	5.27	5.40	5.72	5.90
Realized Oil Price- net of quality offset and transportation[3]	*US$/bbl*	31-Dec-22	71.00	68.80	66.50	68.00	70.20

(1) The numbers in this table may not add due to rounding.
(2) The gas price forecast is based on existing long term contracts net of transportation (if applicable) and adjusted for inflation, along with interruptible gas sales pricing based on forecasts from La Unidad de Planeación Minero Energética ("UPME"), a special administrative unit of the Colombian Ministry of Mines and Energy.
(3) The oil price forecast is based on BGEC's Brent forecast less US$14.00/bbl for quality offset and transportation costs.

Conventional Natural Gas and Light/Medium Crude Oil Reserves Net Present Value Before & After Tax Summary[1]

	Before tax		After tax	
Reserve Category	**31-Dec-22 *(M US$)*[2]**	**Net Asset Value 31-Dec-22 *(C$/share)*[3]**	**31-Dec-22 *(M US$)*[2]**	**Net Asset Value 31-Dec-22 *(C$/share)*[3]**
Proved Developed Producing (PDP)	$ 479,092	$ (3.92)	$ 466,091	$ (4.44)
Total Proved (1P)	$ 993,416	$ 16.43	$ 775,629	$ 7.82
Total Proved + Probable (2P)	**$ 1,937,282**	**$ 53.79**	**$ 1,318,678**	**$ 29.31**
Total Proved + Probable + Possible (3P)	$ 3,142,319	$ 101.48	$ 2,010,743	$ 56.70

(1) The numbers in this table may not add due to rounding.
(2) Net present value is stated in thousands of USD and is discounted at 10 percent. The forecast prices used in the calculation of the present value of future net revenue are based on the price deck described above. The BGEC forecast for conventional natural gas and light/medium crude oil prices at December 31, 2022 are included in the Corporation's Annual Information Form.
(3) Net asset value ("NAV") is calculated as at December 31, 2022 NPV10 less estimated net debt of US$578.2 million (being US$550.8 million of total debt plus working capital deficit of US$27.4 million) divided by 34.1 million basic shares outstanding as at December 31, 2022. NAV calculations are converted to $CAD at December 31, 2022 effective rate of USD:CAD =1.35.

Reserve Life Index ("RLI")[1][2]

Reserve Category	31-Dec-21 (yrs)[3]	31-Dec-22 (yrs)[4]
Proved Developed Producing (PDP)	3.5	2.5
Total Proved (1P)	5.4	5.2
Total Proved + Probable (2P)	**8.9**	**10.0**
Total Proved + Probable + Possible (3P)	14.0	16.8

(1) *The numbers in this table may not add due to rounding.*
(2) *"RLI" Reserve Life Index is calculated by dividing the applicable reserves category by the annualized fourth quarter production.*
(3) *Calculated using average 3 month ending December 31, 2021 natural gas production of 186,145 Mcfpd or 32,657 BOEpd annualized .*
(4) *Calculated using average 3 month ending December 31, 2022 natural gas production of 177,985 Mcfpd or 31,225 BOEpd annualized.*

Year Ended December 31, 2022 Canacol Gross Reserves Reconciliation [1]

PROVED DEVELOPED PRODUCING	Total Oil (MBBL)	Light/Med Crude Oil (MBBL)	Heavy Crude Oil (MBBL)	Conventional Natural Gas (MMCF)	NGL (MBBL)	TOTAL MBOE
Opening Balance (December 31, 2021)	-	-	-	236,023	-	41,408
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions[2]	-	-	-	(12,705)	-	(2,229)
Discoveries[4]	-	-	-	4,797	-	842
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(66,483)	-	(11,664)
Closing Balance (December 31, 2022)	-	-	-	161,633	-	28,357

TOTAL PROVED	Total Oil (MBBL)	Light/Med Crude Oil (MBBL)	Heavy Crude Oil (MBBL)	Conventional Natural Gas (MMCF)	NGL (MBBL)	TOTAL MBOE
Opening Balance (December 31, 2021)	-	-	-	368,366	-	64,626
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions[3]	-	-	-	21,691	-	3,805
Discoveries[4]	1,023	1,023	-	9,839	-	2,749
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(66,483)	-	(11,664)
Closing Balance (December 31, 2022)	1,023	1,023	-	333,412	-	59,516

TOTAL PROVED + PROBABLE	Total Oil (MBBL)	Light/Med Crude Oil (MBBL)	Heavy Crude Oil (MBBL)	Conventional Natural Gas (MMCF)	NGL (MBBL)	TOTAL MBOE
Opening Balance (December 31, 2021)	-	-	-	606,855	-	106,466
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions(3)	-	-	-	19,115	-	3,353
Discoveries(4)	5,725	5,725	-	60,347	-	16,312
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(66,483)	-	(11,664)
Closing Balance (December 31, 2022)	5,725	5,725	-	619,833	-	114,467

TOTAL PROVED + PROBABLE + POSSIBLE	Total Oil (MBBL)	Light/Med Crude Oil (MBBL)	Heavy Crude Oil (MBBL)	Conventional Natural Gas (MMCF)	NGL (MBBL)	TOTAL MBOE
Opening Balance (December 31, 2021)	-	-	-	952,292	-	167,069
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions(3)	-	-	-	(10,542)	-	(1,849)
Discoveries(4)	13,613	13,613	-	135,311	-	37,352
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(66,483)	-	(11,664)
Closing Balance (December 31, 2022)	13,613	13,613	-	1,010,578	-	190,908

(1) The numbers in this table may not add due to rounding.

(2) PDP technical revisions due to transfers to PDNP as certain wells in Nelson and Pandereta that were producing at December 31, 2021 were not producing and awaiting workovers to restart production at December 31, 2022.

(3) Conventional natural gas technical revisions in 1P through to 3P are associated primarily with Clarinete, Pandereta, Siku, San Marcos, Aguas Vivas, Chirimia, and Toronja.

(4) Conventional natural gas discoveries are associated with Alboka, Claxon, and Saxofon on the VIM5 block, Canaflecha-2 on the Esperanza block, Carambolo, Cornamusa on the VIM21 block, and Dividivi, VIM33 block. One conventional oil discovery is associated with Chimela on the VMM45 block.

1P Reserves Metrics Reconciliation – Canacol Working Interest before Royalty(1)(2)

		Calendar 2022		Three-Year Ending December 31, 2022
Net Capital Expenditures (M$ US)(3)	$	151,443	$	321,907
Capital Expenditures - Change in FDC (M$ US)(4)	$	47,584	$	42,089
Total F&D (M$ US)(5)	$	199,027	$	363,996
Net Acquisitions (M$ US)		-		-
Total FD&A (M$ US)(6)(7)	$	199,027	$	363,996
Reserve Additions (MMcfe)		37,360		140,092
Reserve Additions – Net Acquisitions		-		-
Reserve Additions Including Net Acquisitions (MMcfe)		37,360		140,092
1P F&D per Mcfe (US$/Mcfe)(5)	**$**	**5.33**	**$**	**2.60**
1P FD&A per Mcfe (US$/Mcfe)(6)(7)	**$**	**5.33**	**$**	**2.60**

(1) The numbers in this table may not add due to rounding.
(2) All values in this table are stated on a 1P (Total Proved) basis.
(3) The Corporation excludes midstream investments from the F&D calculations, as these capital investments represent long life midstream assets that have multi decade operating life potential, coupled with residual value. 2022, 2021 and 2020 capital expenditures exclude US$9.9 million, US$3.2 million and US$2 million related to expenditures on the Medellin pipeline, respectively. The Corporation also excludes expenditures on corporate assets from the F&D calculations. 2022, 2021 and 2020 capital expenditures exclude US$5 million, US$3 million and US$5.2 million related to expenditures on corporate assets.
(4) "Capital Expenditures – change in FDC" is rounded. FDC is the 1P (Total Proved) future development capital.
(5) 1P F&D – Finding and Development Costs on a 1P (Total Proved) basis.
(6) 1P FD&A - Finding, Development and Acquisition Costs on a 1P (Total Proved) basis.
(7) With the finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

2P Reserves Metrics Reconciliation – Canacol Working Interest before Royalty(1)(2)

		Calendar 2022		Three-Year Ending December 31, 2022
Net Capital Expenditures (M$ US)(3)	$	151,443	$	321,907
Capital Expenditures - Change in FDC (M$ US)(4)	$	98,035	$	97,404
Total F&D (M$ US)(5)	$	249,478	$	419,311
Net Acquisitions (M$ US)		-		-
Total FD&A (M$ US)(6)(7)	$	249,478	$	419,311
Reserve Additions (MMcfe)		112,094		223,705
Reserve Additions – Net Acquisitions		-		-
Reserve Additions Including Net Acquisitions (MMcfe)		112,094		223,705
2P F&D per Mcf (US$/Mcfe)(5)	**$**	**2.23**	**$**	**1.87**
2P FD&A per Mcf (US$/Mcfe)(6)(7)	**$**	**2.23**	**$**	**1.87**

(1) The numbers in this table may not add due to rounding.
(2) All values in this table are stated on a 2P (Total Proved + Probable) basis.
(3) The Corporation excludes midstream investments from the F&D calculations, as these capital investments represent long life midstream assets that have multi decade operating life potential, coupled with residual value. 2022, 2021 and 2020 capital expenditures exclude US$9.9 million, US$3.2 million and US$ 2 million related to expenditures on the Medellin pipeline, respectively. The Corporation also excludes expenditures on corporate assets from the F&D calculations. 2022, 2021 and 2020 capital expenditures exclude US$5 million, US$3 million and US$5.2 million related to expenditures on corporate assets.
(4) "Capital Expenditures – change in FDC" is rounded. FDC is the 2P (Total Proved + Probable) future development capital.
(5) 2P F&D – Finding and Development Costs on a 2P (Total Proved + Probable) basis.
(6) 2P FD&A - Finding, Development and Acquisition Costs on a 2P (Total Proved + Probable) basis.
(7) With the finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

3P Natural Gas Reserves Metrics Reconciliation – Canacol Working Interest before Royalty[(1)(2)]

		Calendar 2022		Three-Year Ending December 31, 2022
Net Capital Expenditures (M$ US)[(3)]	$	151,443	$	321,907
Capital Expenditures - Change in FDC (M$ US)[(4)]	$	98,327	$	97,404
Total F&D (M$ US)[(5)]	$	249,770	$	419,898
Net Acquisitions (M$ US)		-		-
Total FD&A (M$ US)[(6)(7)]	$	249,770	$	419,898
Reserve Additions (MMcfe)		202,363		398,329
Reserve Additions – Net Acquisitions		-		-
Reserve Additions Including Net Acquisitions (MMcfe)		202,363		398,329
3P F&D per Mcf (US$/Mcfe)[(5)]	**$**	**1.23**	**$**	**1.05**
3P FD&A per Mcf (US$/Mcfe)[(6)(7)]	**$**	**1.23**	**$**	**1.05**

(1) The numbers in this table may not add due to rounding.
(2) All values in this table are stated on a 3P (Total Proved + Probable + Possible) basis.
(3) The Corporation excludes midstream investments from the F&D calculations, as these capital investments represent long life midstream assets that have multi decade operating life potential, coupled with residual value. 2022, 2021 and 2020 capital expenditures exclude US$9.9 million, US$3.2 million and US$2 million related to expenditures on the Medellin pipeline, respectively. The Corporation also excludes expenditures on corporate assets from the F&D calculations. 2022, 2021 and 2020 capital expenditures exclude US$5 million, US$3 million and US$5.2 million related to expenditures on corporate assets.
(4) "Capital Expenditures – change in FDC" is rounded. FDC is the 3P (Total Proved + Probable + Possible) future development capital.
(5) 3P F&D – Finding and Development Costs on a 3P (Total Proved + Probable + Possible) basis.
(6) 3P FD&A - Finding, Development and Acquisition Costs on a 3P (Total Proved + Probable + Possible) basis.
(7) With the finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

The recovery and reserve estimates of conventional natural gas and light/medium crude oil are estimates only. There is no guarantee that the estimated reserves will be recovered, and actual reserves of conventional natural gas may prove to be greater than, or less than, the estimates provided.

About Canacol

Canacol is a natural gas and oil exploration and production company with operations focused in Colombia. The Corporation's common stock trades on the Toronto Stock Exchange, the OTCQX in the United States of America, and the Colombia Stock Exchange under ticker symbol CNE, CNNEF, and CNE.C, respectively.

Forward-Looking Information and Statements

This press release contains certain forward-looking statements within the meaning of applicable securities law. Forward-looking statements are frequently characterized by words such as "plan", "expect", "project", "target", "intend", "believe", "anticipate", "estimate" and other similar words, or statements that certain events or conditions "may" or "will" occur, including without limitation statements relating to estimated production rates from the Corporation's properties and intended work programs and associated timelines. Forward-looking statements are based on the opinions and estimates of management at the date the statements are made and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those projected in the forward-looking statements. The Corporation cannot assure that actual results will be consistent with these forward looking statements. They are made as of the date hereof and are subject to change and the Corporation assumes no obligation to revise or update them to reflect new circumstances, except as required by law. Information and guidance provided herein supersedes and replaces any forward looking information provided in prior disclosures. Prospective investors should not place undue reliance on forward looking statements. These factors include the inherent risks involved in the exploration for and development of crude oil and natural gas properties, the uncertainties involved in interpreting drilling results and other geological and geophysical data, fluctuating energy prices, the possibility of cost overruns or unanticipated costs or delays and other uncertainties associated with the oil and gas industry. Other risk factors could include risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities, and other factors, many of which are beyond the control of the Corporation. Other risks are more fully described in the Corporation's most recent Management Discussion and Analysis ("MD&A") and Annual Information Form, which are incorporated herein by reference and are filed on SEDAR at www.sedar.com. Average production figures for a given period are derived using arithmetic averaging of fluctuating historical production data for the entire period indicated and, accordingly, do not represent a constant rate of production for such period and are not an indicator of future production performance. Detailed information in respect of monthly production in the fields operated by the Corporation in Colombia is provided by the Corporation to the Ministry of Mines and Energy of Colombia and is published by the Ministry on its website; a direct link to this information is provided on the Corporation's website.

Use of Non-IFRS Financial Measures *- Such supplemental measures should not be considered as an alternative to, or more meaningful than, the measures as determined in accordance with IFRS as an indicator of the Corporation's performance, and such measures may not be comparable to that reported by other companies. This press release also provides information on adjusted funds from operations. Adjusted funds from operations is a measure not defined in IFRS. It represents cash (used) provided by operating activities before changes in non-cash working capital, settlement of a litigation settlement liability and decommissioning obligation expenditures. The Corporation considers funds from operations a key measure as it demonstrates the ability of the business to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Adjusted funds from operations should not be considered as an alternative to, or more meaningful than, cash (used) provided by operating activities as determined in accordance with IFRS as an indicator of the Corporation's performance. The Corporation's determination of adjusted funds from operations may not be comparable to that reported by other companies. For more details on how the Corporation reconciles its cash provided by operating activities to adjusted funds from operations, please refer to the "Non-IFRS Measures" section of the Corporation's MD&A. Additionally, this press release references Adjusted EBITDAX and operating netback measures. Adjusted EBITDAX is defined as consolidated net income adjusted for interest, income taxes, depreciation, depletion, amortization, exploration expenses and other similar non-recurring or non-cash charges. Operating netback is a benchmark common in the oil and gas industry and is calculated as total natural gas, LNG and petroleum sales, net transportation expenses, less royalties and operating expenses, calculated on a per barrel of oil equivalent basis of sales volumes using a conversion. Operating netback is an important measure in evaluating operational performance as it demonstrates field level profitability relative to current commodity prices. Adjusted EBITDAX and operating netback as presented do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities.*

Operating netback is defined as revenues, net transportation expenses less royalties and operating expenses.

Realized contractual sales is defined as natural gas, oil, and LNG produced and sold plus income received from nominated take-or-pay contracts without the actual delivery of natural gas or LNG and the expiry of the customers' rights to take the deliveries. The Corporation's LNG sales account for less than one percent of the Corporation's total realized contractual natural gas and LNG sales.

The reserves evaluation, effective December 31,

2022, was conducted by the Corporation's independent reserves evaluator Boury Global Energy Consultants Ltd. ("BGEC") and are in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities. The reserves are provided on a Canacol Gross basis in units of thousands of cubic feet ("MMcf") and thousands of barrels of oil equivalent ("MBOE") using a forecast price deck in US dollars. The estimated values may or may not represent the fair market value of the reserve estimates.

"Gross" in relation to the Corporation's interest in production or reserves is its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;

"Net" in relation to the Corporation's interest in production or reserves is its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interest in production or reserves;

"Proved 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.

"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;

"Possible reserves" means those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves;

BOE and CFE Conversions - "BOE" barrel of oil equivalent or "CFE" cubic feet of gas equivalent is derived by converting natural gas to oil or vice versa in the ratio of 5.7 Mcf of natural gas to one bbl of oil. A BOE or CFE conversion ratio of 5.7 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. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 5.7:1, utilizing a conversion on a 5.7:1 basis may be misleading as an indication of value. In this news release, the Corporation has expressed BOE using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Ministry of Mines and Energy of Colombia.

"PDP" means Proved Developed Producing
"1P" means Total Proved
"2P" means Total Proved + Probable
"3P" means Total Proved + Probable + Possible

PDP Reserves replacement ratio: Ratio of reserve additions to production, as reported in financial statements during the fiscal year ended December 31, excluding acquisitions and dispositions on a Proved Developed Producing basis.

1P Reserves replacement ratio: Ratio of reserve additions to production, as reported in financial statements during the fiscal year ended December 31, excluding acquisitions and dispositions on a Total Proved basis.

2P Reserves replacement ratio: Ratio of reserve additions to production, as reported in financial statements during the fiscal year ended December 31, excluding acquisitions and dispositions on a Total Proved + Probable basis.

Finding and development costs per thousand cubic feet (Mcf) represent exploration and development costs incurred per Mcf of Total Proved + Probable reserves added during the year. The Corporation, industry analysts, and investors use such metrics to measure a Corporation's ability to establish a long-term trend of adding reserves at a reasonable cost.

Finding, development and acquisition costs per thousand cubic feet (Mcf) represent property acquisition, exploration, and development costs incurred per Mcf of Total Proved + Probable reserves added during the year. The Corporation, industry analysts, and investors use such metrics to measure a Corporation's ability to establish a long-term trend of adding reserves at a reasonable cost.

With the finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Natural gas recycle ratio is calculated by dividing natural gas netback by finding and development costs.

"RLI" Reserve Life Index is calculated by dividing the applicable reserves category by the annualized fourth quarter production.

This press release contains a number of oil and gas metrics, including F&D, FD&A, reserve replacement and RLI, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies. Such metrics have been included herein to provide readers with additional measures to evaluate the Corporation's performance; however, such measures are not reliable indicators of the future performance of the Corporation and future performance may not compare to the performance in previous periods.

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