



# FIRST QUARTER | 2022

REPORT TO SHAREHOLDERS FOR THE  
PERIOD ENDED MARCH 31, 2022

## Report to Shareholders for the period ended March 31, 2022

(All financial figures are expressed in Canadian dollars (\$) or C\$) and all references to barrels are per barrel of bitumen, unless otherwise noted)

The Corporation's Non-GAAP and Other Financial Measures are detailed in the Advisory section of this report to shareholders. They include: cash operating netback, blend sales, bitumen realization, transportation and storage expense net of transportation revenue, operating expenses net of power revenue, non-energy operating costs, energy operating costs, adjusted funds flow, free cash flow and net debt.

MEG Energy Corp. reported first quarter 2022 operational and financial results on May 2, 2022.

“The first quarter was a record quarter for MEG from both an operational and financial perspective” said Derek Evans, President and Chief Executive Officer. “The team achieved record quarterly production, which together with strong benchmark pricing and low differentials drove record free cash flow in the quarter, setting us up to be able to accelerate debt reduction and initiate share buybacks under our normal course issuer bid in the second quarter of this year.”

Highlights include:

- Record funds flow from operating activities and adjusted funds flow of \$587 million (\$1.87 per share);
- Record bitumen production volumes of 101,128 barrels per day (bbls/d);
- Operating expenses net of power revenue of \$8.98 per barrel, including non-energy operating costs of \$4.74 per barrel. Power revenue offset energy operating costs by 38%, resulting in energy operating costs net of power revenue of \$4.24 per barrel;
- Total capital expenditures of \$88 million primarily directed towards sustaining and maintenance activities, resulting in record free cash flow of \$499 million;
- Completed or announced the repayment of US\$396 million (approximately \$499 million) of outstanding indebtedness in the quarter;
- On March 7, 2022, MEG received approval from the Toronto Stock Exchange (“TSX”) for a normal course issuer bid (“NCIB”) which will allow MEG to buy back up to 10% of its public float, as defined by the TSX, over a one-year period; and
- On March 16, 2022, MEG announced the planned retirement of its Chief Financial Officer effective September 1, 2022. MEG is conducting an external search for its next Chief Financial Officer and will provide an update upon successful completion of the search.

### Blend Sales Pricing

MEG realized an average AWB blend sales price of US\$83.55 per barrel during the first quarter of 2022 compared to US\$65.42 per barrel during the fourth quarter of 2021. The increase in average AWB blend sales price quarter over quarter was primarily a result of the average WTI price increasing by US\$17.10 per barrel. MEG sold 58% of its sales volumes at the U.S. Gulf Coast (“USGC”) in the first quarter of 2022 compared to 48% during the fourth quarter of 2021.

The increase quarter over quarter is primarily the result of apportionment on the Enbridge mainline being 10% in the first quarter of 2022 compared to 21% in the fourth quarter of 2021.

Transportation and storage expense net of transportation revenue averaged US\$7.01 per barrel of AWB blend sales in the first quarter of 2022 compared to US\$6.33 per barrel of AWB blend sales in the fourth quarter of 2021. The increase was primarily a result of more barrels being sold in the USGC in the quarter compared to the fourth quarter of 2021.

### Operational Performance

Bitumen production averaged 101,128 bbls/d at a steam-oil ratio ("SOR") of 2.43 in the first quarter of 2022, compared to 100,698 bbls/d at a SOR of 2.42 in the fourth quarter of 2021. Increased steam utilization and ongoing optimization and recompletion work all contributed to strong field-wide production performance in the first quarter of 2022 as well as the fourth quarter of 2021. Also contributing to this strong performance was the Corporation's commitment in the last half of 2021 to increase spending on incremental well capital aimed at fully utilizing the 100,000 barrels per day processing capacity of the Christina Lake plant.

Non-energy operating costs averaged \$4.74 per barrel of bitumen sales in the first quarter of 2022 compared to \$4.56 per barrel in the fourth quarter of 2021. Energy operating costs, net of power revenue, averaged \$4.24 per barrel in the first quarter of 2022 compared to \$3.64 per barrel in the fourth quarter of 2021. This increase quarter over quarter resulted primarily from stronger natural gas prices. Power revenue offset energy operating costs by 38% during the first quarter of 2022 compared to 41% in the fourth quarter of 2021.

General & administrative expense ("G&A") was relatively consistent quarter over quarter with \$14 million, or \$1.61 per barrel of production, in the first quarter of 2022 compared to \$15 million, or \$1.58 per barrel of production, in the fourth quarter of 2021.

### Funds Flow from Operating Activities, Adjusted Funds Flow and Net Earnings (Loss)

The Corporation's cash operating netback averaged \$70.21 per barrel in the first quarter of 2022 compared to \$37.87 per barrel in the fourth quarter of 2021. This increase in cash operating netback was primarily driven by the increase in average bitumen realization due to the higher WTI price in the first quarter of 2022. Cash operating netback during the fourth quarter of 2021 was impacted by realized commodity price risk management losses. The increased cash operating netback was the main driver for the increase in both the Corporation's funds flow from operating activities and adjusted funds flow from \$266 million in the fourth quarter of 2021 to \$587 million in the first quarter of 2022.

The Corporation recognized net earnings of \$362 million in the first quarter of 2022 compared to \$177 million in the fourth quarter of 2021. This increase in net earnings was primarily due to stronger global crude oil prices.

### Capital Expenditures

Capital expenditures in the first quarter of 2022 totaled \$88 million compared to \$106 million in the fourth quarter of 2021. Capital invested in the quarter was primarily directed towards sustaining and maintenance activities and included incremental capital to allow the Corporation to fully utilize the Christina Lake central plant facility's oil processing capacity of approximately 100,000 bbls/d, prior to any impact from scheduled maintenance activity or outages.

### Debt Repayment

On January 18, 2022, MEG completed the redemption of US\$225 million (approximately \$285 million) of MEG's outstanding 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625% plus accrued and unpaid interest to, but not including the redemption date.

On March 3, 2022, the Corporation issued a notice to redeem the remaining US\$171 million (approximately \$214 million) of MEG's outstanding 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625%, plus accrued and unpaid interest to, but not including the redemption date. The redemption was completed on April 4, 2022. Inclusive of the redemption, MEG has now redeemed, in full, the original US\$750 million aggregate principal amount of the senior secured second lien notes.

Post this redemption, the Corporation will have repaid approximately US\$2 billion of outstanding indebtedness since 2018 and remains committed to continued debt reduction as a key component of its capital allocation strategy in 2022.

## Capital Allocation Strategy Update

On March 7, 2022, MEG received approval from the TSX for a NCIB which will allow MEG to purchase for cancellation, from time to time, as the Corporation considers advisable, up to a maximum of 27,242,211 common shares of MEG. The NCIB became effective March 10, 2022 and will terminate on March 9, 2023 or such earlier time as the NCIB is completed or terminated at the option of MEG. MEG's net debt balance at the end of the first quarter of 2022 was approximately US\$1.72 billion. Once the Corporation's net debt balance reaches US\$1.7 billion MEG will allocate approximately 25% of free cash flow generated to share buybacks with the remaining free cash flow applied to ongoing debt reduction until the Corporation's net debt balance reaches US\$1.2 billion. In the current commodity price environment MEG expects to reach its US\$1.2 billion net debt target in the third quarter of 2022.

Once the US\$1.2 billion net debt target is reached the Corporation intends to increase the percentage of free cash flow allocated to share buybacks to approximately 50% with the remainder applied to further debt reduction until the Corporation reaches its net debt floor of US\$600 million at which time 100% of free cash flow will be returned to shareholders. At current production levels, this net debt floor implies a net debt to EBITDA multiple of approximately 1.0 times at a long-term US\$50 per barrel WTI price. In the current commodity price environment MEG expects to reach its net debt floor in the second half of 2023.

## Sustainability

On April 7, 2022 the Canadian federal government announced an investment tax credit for carbon capture, utilization and storage projects for industries across Canada. MEG believes this announcement is a positive step in the Oilsands Pathways to Net Zero ("Pathways") Alliance's efforts to work collaboratively with governments to help Canada achieve its climate goals and ensure our country can be the world's preferred supplier of responsibly-produced oil. The Pathways Alliance anticipates that this tax credit, together with support from the Alberta government, will help advance the Pathways Alliance unprecedented plan to achieve meaningful emissions reductions by 2030 and ultimately the goal of net zero emissions from oil sands operations by 2050.

## ADVISORY

### Forward-Looking Information

This quarterly report contains forward-looking information and should be read in conjunction with the "Forward-Looking Information" contained within the Advisory section of this quarter's Management's Discussion and Analysis and Press Release.

### Non-GAAP and Other Financial Measures

Certain financial measures in this report to shareholders are non-GAAP financial measures or ratios, supplementary financial measures and capital management measures. These measures are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP and other financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Please refer to section 14 "Non-GAAP and Other Financial Measures" of the Corporation's first quarter of 2022 Management's Discussion and Analysis for detailed descriptions of these measures.



## MANAGEMENT'S DISCUSSION AND ANALYSIS

*This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three months ended March 31, 2022 was approved by the Corporation's Audit Committee on May 2, 2022. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three months ended March 31, 2022, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2021, the 2021 annual MD&A and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in millions of Canadian dollars, except where otherwise indicated.*

*Unless otherwise indicated, all per barrel figures are based on bitumen sales volumes.*

*Certain financial measures in this MD&A are non-GAAP financial measures or ratios, supplementary financial measures and capital management measures. These measures are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP and other financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A for further descriptions of the measures noted below.*

*1. Non-GAAP financial measures and ratios:*

- Cash operating netback*
- Blend sales*
- Bitumen realization*
- Transportation and storage expense net of transportation revenue*
- Operating expenses net of power revenue*
- Per barrel figures associated with non-GAAP financial measures*

*2. Supplementary financial measures and ratios:*

- Non-energy operating costs*
- Energy operating costs*
- Per barrel figures associated with supplementary financial measures*

*3. Capital management measures:*

- Adjusted funds flow*
- Free cash flow*
- Net debt*

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## 1. BUSINESS DESCRIPTION

MEG is an energy company focused on sustainable *in situ* thermal oil production in the southern Athabasca oil region of Alberta, Canada. MEG is actively developing innovative enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods to improve the responsible economic recovery of oil as well as lower carbon emissions. MEG transports and sells thermal oil (known as Access Western Blend or "AWB") to customers throughout North America and internationally.

MEG owns a 100% working interest in approximately 410 square miles of mineral leases. GLJ Ltd. ("GLJ"), an independent qualified reserves and resources evaluator, estimated that the leases it had evaluated, as at December 31, 2021, contained approximately 2.0 billion barrels of gross proved plus probable ("2P") bitumen reserves at the Christina Lake Project. For information regarding MEG's estimated reserves contained in the report prepared by GLJ, please refer to the Corporation's most recently filed AIF, which is available on the Corporation's website at [www.megenergy.com](http://www.megenergy.com) and is also available on the SEDAR website at [www.sedar.com](http://www.sedar.com).

## 2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

Global crude oil prices strengthened in the first quarter of 2022 as a result of improved demand and declining inventories. With the February 2022 Russian invasion of Ukraine, the imposition of sanctions against Russia caused significant upward pressure on global crude oil prices driven by concerns over potential for major disruptions to global crude oil supply. As a result of this increased pricing and strong production performance, the Corporation generated both funds flow from operating activities and adjusted funds flow of \$587 million in the first quarter of 2022 compared to \$121 million and \$127 million, respectively, in the first quarter of 2021. The Corporation's realized blend sales price averaged \$105.79 per barrel in the first quarter of 2022 compared to \$61.28 per barrel in the first quarter of 2021 resulting primarily from a US\$36.45 per barrel increase in the WTI benchmark price.

Production volumes averaged a record 101,128 barrels per day in the first quarter of 2022 compared to 90,842 barrels per day during the first quarter of 2021 and 100,698 barrels per day in the fourth quarter of 2021. Increased steam utilization and ongoing optimization and recompletion work all contributed to strong field-wide production performance to date in 2022. Also contributing to the increase was the Corporation's commitment in the last half of 2021 to increase spending on incremental well capital aimed at fully utilizing the 100,000 barrels per day processing capacity of the Christina Lake plant.

Capital expenditures were \$88 million in the first quarter of 2022 compared to \$70 million during the first quarter of 2021. The majority of the \$88 million invested in the quarter was directed towards sustaining and maintenance activities. The Corporation continues to maintain annual 2022 capital expenditures guidance of \$375 million.

Free cash flow in the first quarter of 2022 hit a quarterly record of \$499 million. This compares to \$57 million in the first quarter of 2021.

The Corporation recognized net earnings of \$362 million in the first quarter of 2022 compared to a net loss of \$17 million in the first quarter of 2021. Increased earnings were mainly due to stronger global crude oil prices. The net loss recognized in the first quarter of 2021 was impacted by losses on commodity risk management. The Corporation has not entered into any WTI or WTI:WCS differential commodity risk management contracts for 2022.

On January 18, 2022 debt totaling US\$225 million was redeemed and the announced redemption of the remaining balance of the Corporation's 6.50% senior secured second lien notes of US\$171 million occurred subsequent to the first quarter on April 4, 2022. Post these redemptions, the Corporation will have repaid approximately US\$2 billion of outstanding indebtedness since 2018 and remains committed to continued debt reduction as a key component of its capital allocation strategy in 2022.

As at March 31, 2022 cash and cash equivalents were \$290 million. The Corporation exited the quarter with net debt of approximately \$2.15 billion (approximately US\$1.72 billion) compared to net debt of approximately \$2.40 billion (approximately US\$1.90 billion) at December 31, 2021.

On March 7, 2022, the Corporation received approval from the Toronto Stock Exchange ("TSX") for a normal course issuer bid ("NCIB") which will allow the Corporation to purchase for cancellation, from time to time, as the

Corporation considers advisable, up to a maximum of 27,242,211 common shares of the Corporation. The NCIB became effective March 10, 2022 and will terminate on March 9, 2023 or such earlier time as the NCIB is completed or terminated at the option of the Corporation. The Corporation's net debt balance at the end of the first quarter of 2022 was approximately US\$1.72 billion. Once the Corporation's net debt balance reaches US\$1.7 billion the Corporation will allocate approximately 25% of free cash flow generated to share buybacks with the remaining free cash flow applied to ongoing debt reduction until the Corporation's net debt balance reaches US\$1.2 billion. In the current commodity price environment MEG expects to reach its US\$1.2 billion net debt target in the third quarter of 2022.

Once the US\$1.2 billion net debt target is reached the Corporation intends to increase the percentage of free cash flow allocated to share buybacks to approximately 50% with the remainder applied to further debt reduction until the Corporation reaches its net debt floor of US\$600 million at which time 100% of free cash flow will be returned to shareholders. At current production levels, this net debt floor implies a net debt to EBITDA multiple of approximately 1.0 times at a long-term US\$50 per barrel WTI price. In the current commodity price environment the Corporation expects to reach its net debt floor in the second half of 2023.

On March 16, 2022, the Corporation announced the planned retirement of its Chief Financial Officer effective September 1, 2022. MEG is conducting an external search for its next Chief Financial Officer and will provide an update upon successful completion of this search.

The following table summarizes selected operational and financial information of the Corporation for the periods noted. All dollar amounts are stated in Canadian dollars (\$) or C\$) unless otherwise noted and all per barrel figures are based on bitumen sales volumes:

	2022	2021				2020		
<i>(\$millions, except as indicated)</i>	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Bitumen production - bbls/d	<b>101,128</b>	100,698	91,506	91,803	90,842	91,030	71,516	75,687
Steam-oil ratio	<b>2.43</b>	2.42	2.56	2.39	2.37	2.31	2.36	2.32
Bitumen sales - bbls/d	<b>100,186</b>	98,894	92,251	89,980	87,298	95,731	67,569	70,397
Bitumen realization <sup>(1)</sup> - \$/bbl	<b>97.28</b>	71.06	64.91	60.09	52.34	38.64	39.68	10.18
Operating expenses net of power revenue <sup>(1)</sup> - \$/bbl	<b>8.98</b>	8.20	7.17	5.54	5.25	6.98	6.05	6.14
Non-energy operating costs <sup>(2)</sup> - \$/bbl	<b>4.74</b>	4.56	4.46	3.84	4.05	4.70	3.96	4.09
Cash operating netback <sup>(1)</sup> - \$/bbl	<b>70.21</b>	37.87	37.31	31.30	26.03	18.66	16.58	25.84
General & administrative expense - \$/bbl of bitumen production volumes	<b>1.61</b>	1.58	1.72	1.56	1.77	1.65	1.50	1.29
Funds flow from operating activities	<b>587</b>	260	212	160	121	81	19	69
Adjusted funds flow <sup>(3)</sup>	<b>587</b>	266	239	166	127	84	26	89
Per share, diluted	<b>1.87</b>	0.85	0.77	0.53	0.41	0.27	0.09	0.29
Revenues	<b>1,531</b>	1,307	1,091	1,009	914	786	533	307
Net earnings (loss)	<b>362</b>	177	54	68	(17)	16	(9)	(80)
Per share, diluted	<b>1.15</b>	0.57	0.17	0.22	(0.06)	0.05	(0.03)	(0.26)
Capital expenditures	<b>88</b>	106	84	71	70	40	35	20
Net debt <sup>(3)</sup> - C\$	<b>2,150</b>	2,401	2,559	2,661	2,798	2,798	2,981	2,976
Net debt <sup>(3)</sup> - US\$	<b>1,722</b>	1,897	2,007	2,145	2,226	2,194	2,237	2,186

(1) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

(2) Supplementary financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

(3) Capital management measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

### 3. SUSTAINABILITY

On April 7, 2022 the Canadian federal government announced an investment tax credit for carbon capture, utilization and storage projects for industries across Canada. MEG believes this announcement is a positive step in the Oilsands Pathways to Net Zero ("Pathways") Alliance's efforts to work collaboratively with governments to help Canada achieve its climate goals and ensure our country can be the world's preferred supplier of responsibly-produced oil. The Pathways Alliance anticipates that this tax credit, together with support from the Alberta government, will help advance the Pathways Alliance unprecedented plan to achieve meaningful emissions reductions by 2030 and ultimately the goal of net zero emissions from oil sands operations by 2050.

For further details on the Corporation's approach to ESG matters, please refer to the Corporation's 2021 ESG Report available in the "Sustainability" section of the Corporation's website at [www.megenergy.com](http://www.megenergy.com) and the most recently filed AIF on [www.sedar.com](http://www.sedar.com).

### 4. NET EARNINGS (LOSS)

	Three months ended March 31	
	2022	2021
<i>(\$millions, except per share amounts)</i>		
Net earnings (loss)	\$ 362	\$ (17)
Per share, diluted	\$ 1.15	\$ (0.06)

Increased net earnings during the three months ended March 31, 2022 was primarily due to stronger global crude oil prices. The net loss during the three months ended March 31, 2021 was impacted by losses on commodity risk management.

### 5. REVENUES

Revenues represents the total of petroleum revenue, including sales of third-party products related to marketing asset optimization activity, net of royalties, and other revenue.

	Three months ended March 31	
	2022	2021
<i>(\$millions)</i>		
Sales from:		
Production	\$ 1,393	\$ 695
Purchased product <sup>(1)</sup>	161	198
Petroleum revenue	\$ 1,554	\$ 893
Royalties	(47)	(7)
Petroleum revenue, net of royalties	\$ 1,507	\$ 886
Power revenue	\$ 23	\$ 25
Transportation revenue	1	3
Other revenue	\$ 24	\$ 28
Revenues	\$ 1,531	\$ 914

<sup>(1)</sup> The associated third-party purchases are included in the consolidated statement of earnings (loss) and comprehensive income (loss) under the caption "Purchased product".

During the three months ended March 31, 2022, revenues increased 67% from the same period of 2021 primarily as a result of the increase in the average blend sales price which was mostly driven by the increase in WTI prices.



## 6. RESULTS OF OPERATIONS

### Bitumen Production and Steam-Oil Ratio

	Three months ended March 31	
	2022	2021
Bitumen production – bbls/d	101,128	90,842
Steam-oil ratio (SOR)	2.43	2.37

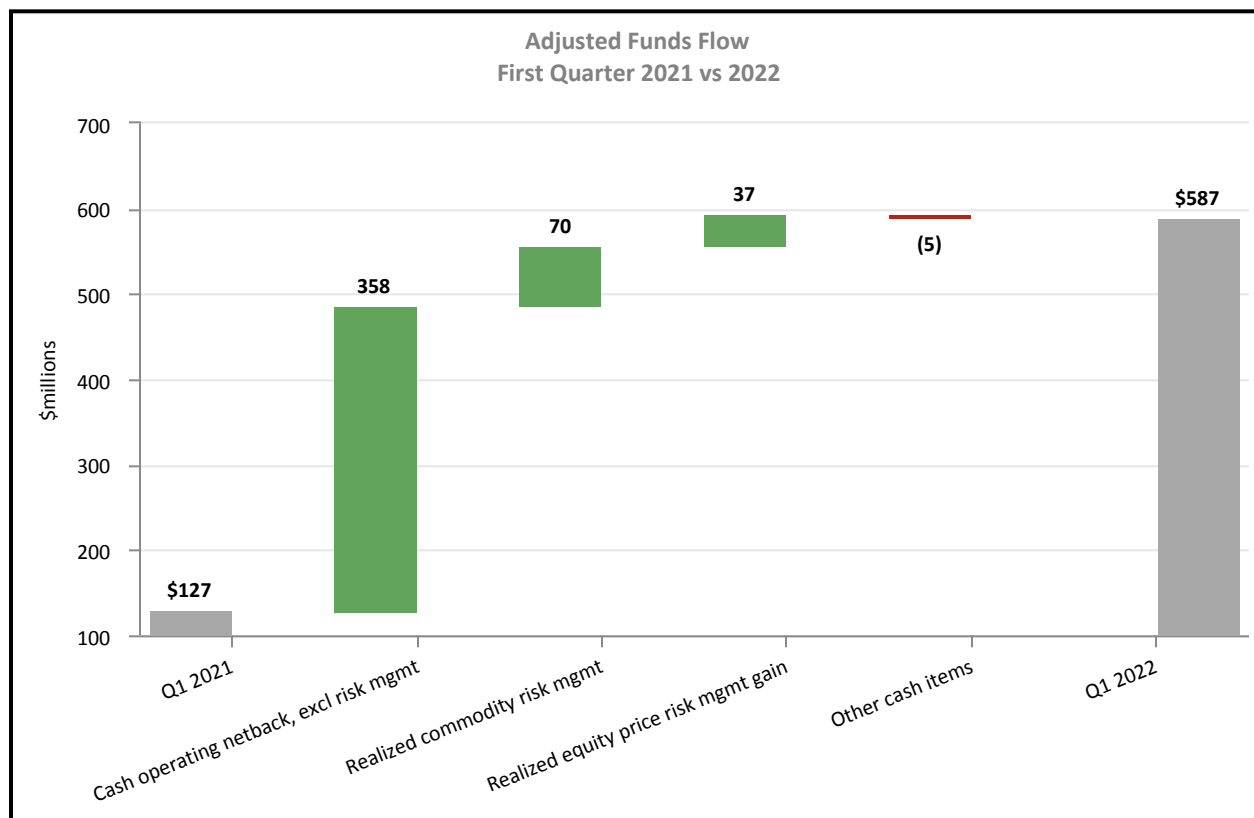
### Bitumen Production

Bitumen production increased 11% during the three months ended March 31, 2022 compared to the same period of 2021. Increased steam utilization and ongoing optimization and recompletion work all contributed to strong field-wide production performance to date in 2022. Also contributing to the increase was the Corporation's commitment in the last half of 2021 to increase spending on incremental well capital aimed at fully utilizing the 100,000 barrels per day processing capacity of the Christina Lake plant.

### Steam-Oil Ratio

The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is Steam-Oil Ratio ("SOR"), which is an efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR increased for the three months ended March 31, 2022, compared to the same period of 2021, due to the timing of new well pairs converted to SAGD.

### Funds Flow from Operating Activities and Adjusted Funds Flow



During the three months ended March 31, 2022, funds flow from operating activities and adjusted funds flow increased compared to the same period of 2021. The increase was primarily driven by the Corporation's increased cash operating netback, which was primarily impacted by an increase in global crude oil prices.

The following table reconciles funds flow from operating activities to adjusted funds flow:

(\$millions)	Three months ended March 31	
	2022	2021
Funds flow from operating activities	\$ 587	\$ 121
Adjustments:		
Payments on onerous contract	—	6
Adjusted funds flow <sup>(1)</sup>	\$ 587	\$ 127
Adjusted funds flow per share - diluted	\$ 1.87	\$ 0.41

(1) Capital management measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

Funds flow from operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as funds flow from operating activities excluding items not considered part of ordinary continuing operating results. Adjusted funds flow is used by management to analyze the Corporation's operating performance and cash flow generating ability. By excluding non-recurring adjustments from cash flows, the adjusted funds flow measure provides a meaningful metric for management by establishing a clear link between the Corporation's cash flows and the cash operating netback.

### Cash Operating Netback

The following table summarizes the Corporation's cash operating netback. Unless otherwise indicated, the per barrel calculations are based on bitumen sales volume.

(\$millions, except as indicated)	Three months ended March 31			
	2022		2021	
	\$/bbl		\$/bbl	
Sales from production	\$ 1,393		\$ 695	
Sales from purchased product <sup>(1)</sup>	161		198	
Petroleum revenue	1,554		893	
Purchased product <sup>(1)</sup>	(160)		(185)	
Blend sales <sup>(2)(3)</sup>	\$ 1,394	\$ 105.79	\$ 708	\$ 61.28
Diluent expense	(517)	(8.51)	(296)	(8.94)
Bitumen realization <sup>(3)</sup>	877	97.28	412	52.34
Transportation and storage expense net of transportation revenue <sup>(3)(4)</sup>	(117)	(12.97)	(90)	(11.41)
Royalties	(47)	(5.24)	(7)	(0.85)
Operating expenses net of power revenue <sup>(3)</sup>	(81)	(8.98)	(41)	(5.25)
Cash operating netback before realized commodity risk management	632	70.09	274	34.83
Realized gain (loss) on commodity risk management	1	0.12	(69)	(8.80)
Cash operating netback <sup>(3)</sup>	\$ 633	\$ 70.21	\$ 205	\$ 26.03
Bitumen sales volumes - bbls/d		100,186		87,298

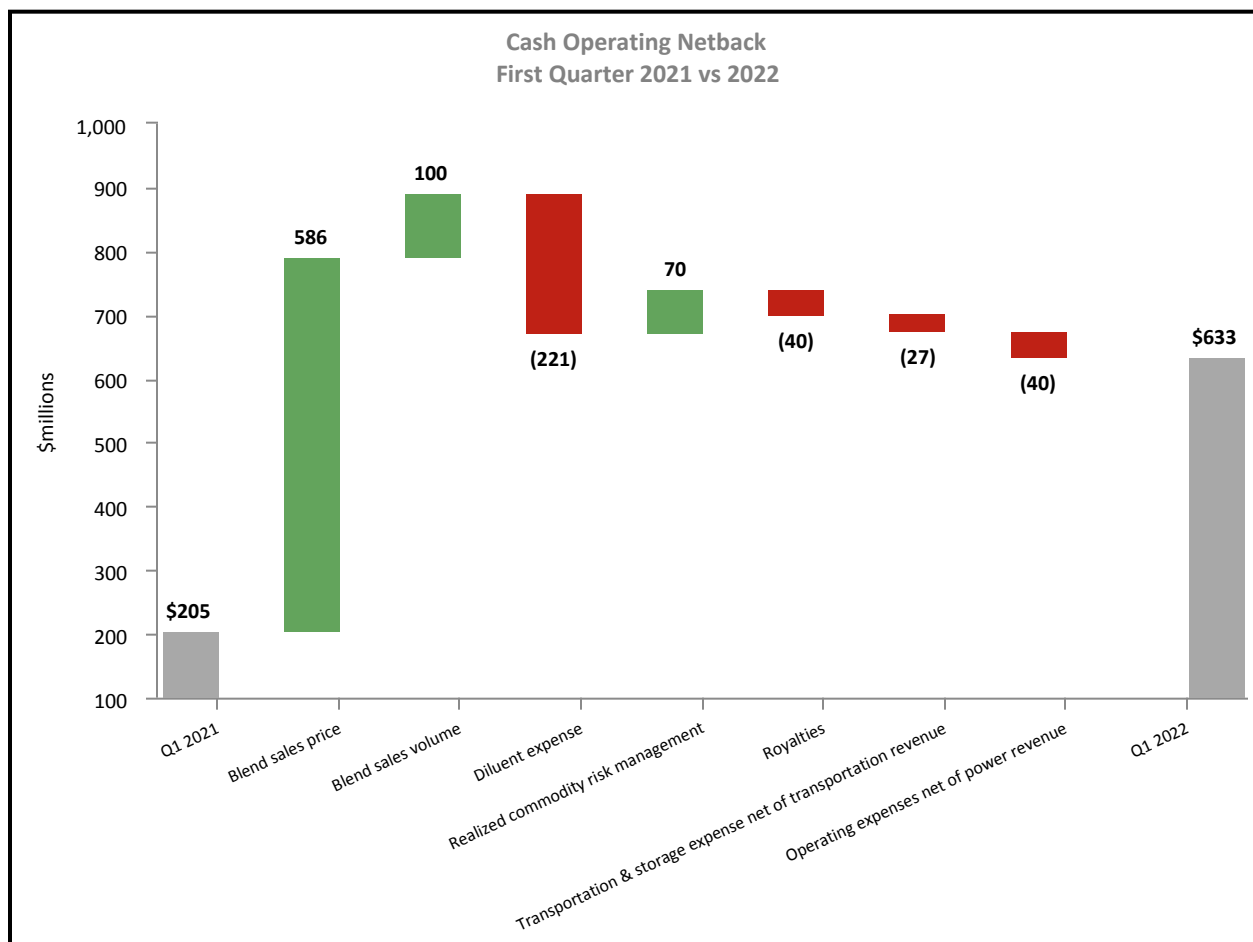
(1) Sales and purchases of oil products related to marketing asset optimization activities.

(2) Blend sales per barrel are based on blend sales volumes.

(3) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

(4) Transportation and storage expense net of transportation revenue includes costs associated with moving and storing blended barrels to optimize the timing of delivery, net of third-party recoveries on diluent transportation arrangements.

Blend sales includes sales from purchased product net of the cost of purchased product related to marketing asset optimization activities undertaken in the period. Marketing asset optimization is focused on the recovery of fixed costs related to transportation and storage contracts during periods of underutilization of these assets, with the goal to strengthen cash operating netback. Marketing asset optimization activities consist of the purchase and sale of third-party products. The Corporation does not engage in speculative trading. The purchase and sale of third-party products to facilitate asset optimization activities requires the elimination of price risk pursuant to policies approved by the Corporation's Board of Directors which can be achieved either through the counterparty or through financial price risk management.



### Bitumen Realization

Bitumen realization represents the Corporation's blend sales less the cost of diluent, expressed on a per barrel of bitumen sold basis. Blend sales represents the Corporation's revenue from its oil blend known as AWB, which is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. Also included in blend sales are net profits from third-party purchases and sales associated with asset optimization activities. The cost of diluent is impacted by Canadian and U.S. benchmark pricing, the amount of diluent required which is impacted by seasonality and pipeline specifications, the cost of transporting diluent to the production site from both Edmonton and U.S. Gulf Coast ("USGC") markets, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar. The cost of diluent purchased is partially offset by the sales of such diluent in blend volumes. Bitumen realization per barrel fluctuates primarily based on average benchmark prices and light:heavy oil differentials.

	Three months ended March 31			
	2022		2021	
<i>(\$millions, except as indicated)</i>	<i>\$/bbl</i>		<i>\$/bbl</i>	
Sales from production	\$	1,393	\$	695
Sales from purchased product <sup>(1)</sup>		161		198
Petroleum revenue	\$	1,554	\$	893
Purchased product <sup>(1)</sup>		(160)		(185)
Blend sales <sup>(2)(3)</sup>	\$	1,394	\$	708
Diluent expense		(517)		(296)
Bitumen realization <sup>(3)</sup>	\$	877	\$	412
		\$ 105.79		\$ 61.28
		(8.51)		(8.94)
				52.34

(1) Sales and purchases of oil products related to marketing asset optimization activities.

(2) Blend sales per barrel are based on blend sales volumes.

(3) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

Blend sales price increased by \$44.51 per barrel, or 73%, during the three months ended March 31, 2022 compared to the same period of 2021. The increase in blend sales price during the three months ended March 31, 2022 is primarily due to a higher WTI price. During the three months ended March 31, 2022, the Corporation sold 58% of its blend sales volumes via pipeline at the USGC compared to 38% in the same period of 2021. Apportionment levels averaged 10% during the three months ended March 31, 2022 compared to 48% in the same period of 2021.

Diluent expense per barrel represents the cost of diluent that is unrecovered through blended sales. The diluent expense per barrel during the three months ended March 31, 2022 was in line with the same period of 2021 as the WTI:WCS differentials were similar in each period.

Total diluent expense was \$517 million during the three months ended March 31, 2022 compared to \$296 million during the same period of 2021. This translates to a cost per barrel of diluent during the three months ended March 31, 2022 of \$124.23 compared to \$80.34 for the same period of 2021. The cost per barrel is impacted by the benchmark condensate price, transportation costs to move diluent to the Christina Lake production site and the timing of use of inventory. The cost of diluent recognized is determined on a weighted-average cost basis and diluent volumes are typically held in inventory for 30 to 60 days. Approximately half of the diluent is sourced from each of Edmonton and Mont Belvieu, Texas. Refer to condensate prices within the "BUSINESS ENVIRONMENT" section of this MD&A for further details.

#### Transportation and Storage Expense net of Transportation Revenue

The Corporation's marketing strategy focuses on maximizing the realized AWB sales price after transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access.

	Three months ended March 31			
	2022		2021	
<i>(\$millions, except as indicated)</i>	<i>\$/bbl</i>		<i>\$/bbl</i>	
Transportation and storage expense	\$	(118)	\$	(93)
Transportation revenue		1		3
Transportation and storage expense net of transportation revenue	\$	(117)	\$	(90)
Bitumen sales volumes - bbls/d		100,186		87,298

During the three months ended March 31, 2022, transportation and storage expense net of transportation revenue, on a total basis and a per barrel basis, increased compared to the same period of 2021. Due to low apportionment levels during the three months ended March 31, 2022, the Corporation was able to ship more volumes to the higher priced USGC market in this period which primarily drove the increase in transportation costs compared to the same period of 2021.

The Corporation partially mitigated the cost of unutilized transportation and storage assets through the purchase and sale of non-proprietary product, or asset optimization activities, which added \$1 million, or \$0.04 per barrel to blend sales, during the three months ended March 31, 2022 compared to \$13 million, or \$1.07 per barrel to blend sales, during the same period of 2021. After considering the impact of asset optimization activities, transportation and storage expense net of transportation revenue was \$12.93 per barrel during the three months ended March 31, 2022 compared to \$10.34 per barrel during the same period of 2021. Compared to the same period of 2021, the Corporation moved more proprietary barrels to the USGC and asset optimization activities declined.

### Royalties

The oil sands royalty framework under the Oil Sands Royalty Regulation, 2009, establishes royalty rates for bitumen that are linked to price. The Alberta oil sands royalty payable is based on these price-sensitive royalty rates and applied to production volumes. The applicable royalty rates change depending on whether the project's status is pre-payout or post-payout. "Payout" is generally defined as the point in time when a project has generated enough net revenue to recover its costs and provide a designated return allowance. When a project reaches payout, its cumulative revenue equals or exceeds its cumulative costs. Costs include specified allowed capital and operating costs pursuant to the Oil Sands Allowed Costs (Ministerial) Regulation. The royalty payable for pre-payout projects is based on the project's gross revenue multiplied by a gross revenue royalty rate. The gross revenue royalty rate starts at 1% and increases for every dollar that the world oil price, as reflected by the WTI crude oil price in Canadian dollars, is priced above \$55 per barrel, to a maximum of 9% when the WTI crude oil price is \$120 per barrel or higher. The royalty payable for post-payout projects is the greater of (i) the gross revenue royalty; or (ii) the net revenue royalty based on the net revenue royalty rate. The net revenue royalty rate is based on a formula which starts at 25% and increases for every dollar the WTI crude oil price is above \$55 per barrel to a maximum of 40% when the WTI crude oil price is \$120 per barrel or higher.

The Corporation's Christina Lake operation is currently in pre-payout and the applicable royalty rate is applied to gross revenues for royalty purposes.

	Three months ended March 31	
	2022	2021
<i>(\$millions, except as indicated)</i>	<i>\$/bbl</i>	<i>\$/bbl</i>
Royalties	\$ (47)	\$ (5.24)
	\$ (7)	\$ (0.85)

The WTI benchmark price increased 63% during the three months ended March 31, 2022, compared to the same period of 2021, which increased the gross royalty rate applied from 2% to 7%.

### Operating Expenses net of Power Revenue

Operating expenses net of power revenue are comprised of the sum of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-related operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate steam and power at the Corporation's facilities. Power revenue is recognized from the sale of surplus power generated by the Corporation's cogeneration facilities at the Christina Lake Project. The Corporation utilizes thermally efficient cogeneration facilities to provide a portion of its steam and electricity requirements. Any excess power that is sold into the Alberta electrical grid displaces other power sources that have a higher carbon intensity, thereby reducing the Corporation's overall carbon footprint.

	Three months ended March 31			
	2022		2021	
<i>(\$millions, except as indicated)</i>	\$/bbl		\$/bbl	
Non-energy operating costs <sup>(1)</sup>	\$ (43)	\$ (4.74)	\$ (32)	\$ (4.05)
Energy operating costs <sup>(1)</sup>	(61)	(6.80)	(34)	(4.34)
Power revenue	23	2.56	25	3.14
Operating expenses net of power revenue <sup>(2)</sup>	\$ (81)	\$ (8.98)	\$ (41)	\$ (5.25)
Average natural gas purchase price (C\$/mcf)	\$	5.35	\$	3.62
Average realized power sales price (C\$/Mwh)	\$	91.50	\$	93.27

(1) Supplementary financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

(2) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

Total non-energy operating costs and non-energy operating costs per barrel have increased for the three months ended March 31, 2022, compared to the same period of 2021. The increase is primarily due to increased staff costs, increased well workovers, higher priced chemicals and increased overall maintenance activity.

Energy operating costs increased predominantly due to the AECO natural gas market strengthening by approximately 50%, as well as increased consumption as production increased. Power revenue offset energy operating costs by 38% during the three months ended March 31, 2022 compared to 74% during the same period of 2021. Power revenue during the first quarter of 2021 included the impact of physical risk management contracts on power sales. The Alberta power market weakened by 7% during the three months ended March 31, 2022 compared to the same period of 2021.

#### Realized Gain or Loss on Commodity Risk Management

From time to time, the Corporation enters into financial commodity risk management contracts. The Corporation has not entered into any WTI or WTI:WCS differential commodity risk management contracts for 2022. Realized gains on commodity risk management contracts were recognized during the three months ended March 31, 2022 associated with fixed natural gas purchase contracts in place. During the same period of 2021, the Corporation held crude oil, natural gas and condensate commodity risk management contracts. The realized loss recognized during this period primarily relates to a strengthening WTI price compared to WTI fixed price contracts in place. Refer to the commodity risk management discussion within the "OTHER OPERATING RESULTS" section of this MD&A for further details.

	Three months ended March 31			
	2022		2021	
<i>(\$millions, except as indicated)</i>	\$/bbl		\$/bbl	
Realized gain (loss) on commodity risk management	\$ 1	\$ 0.12	\$ (69)	\$ (8.80)

#### Capital Expenditures

	Three months ended March 31	
<i>(\$millions)</i>	2022	2021
Sustaining and maintenance	\$ 80	\$ 65
Phase 2B brownfield expansion	—	4
Field infrastructure, corporate and other	8	1
	\$ 88	\$ 70

The majority of the \$88 million invested in the three months ended March 31, 2022 was directed towards sustaining and maintenance activities which includes incremental capital to allow the Corporation to fully utilize

the Christina Lake central plant facility's oil processing capacity of approximately 100,000 barrels per day, prior to any impact from scheduled maintenance activity or outages.

## 7. OUTLOOK

On November 29, 2021 the Corporation released its 2022 capital and operating budget.

The Corporation's 2022 production and operational guidance remains unchanged from the budget and reflects the impact of a scheduled 30-day turnaround in the second quarter at its Christina Lake Phase 2B facility which is expected to impact full year production by approximately 6,000 barrels per day.

The Corporation has capacity to ship 100,000 barrels per day of AWB blend sales, on a pre-apportionment basis, to the USGC market via its committed capacity on the Flanagan South and Seaway pipeline systems ("FSP"). The Corporation expects to sell approximately two-thirds of its full year 2022 AWB blend sales volumes into the USGC via FSP with the remainder being sold into the Edmonton market. The Corporation expects full year 2022 total transportation costs to average between US\$7.50 and US\$8.00 per barrel of AWB blend sales.

The Corporation has not entered into any WTI or WTI:WCS differential commodity risk management contracts for 2022.

<b>Summary of 2022 Guidance<sup>(1)</sup></b>	
Bitumen production - annual average	94,000 - 97,000 bbls/d
Non-energy operating costs	\$4.50 - \$4.80 per bbl
G&A expense	\$1.70 - \$1.85 per bbl
Capital expenditures	\$375 million

*(1) 2022 guidance includes the impact of a scheduled 30-day turnaround at the Corporation's Christina Lake Phase 2B facility which is expected to impact annual production by approximately 6,000 barrels per day.*

## 8. BUSINESS ENVIRONMENT

The following table shows industry commodity pricing information and foreign exchange rates for the periods noted to assist in understanding their impact on the Corporation's financial results:

AVERAGE BENCHMARK COMMODITY PRICES	2022	2021				2020		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
<b>Crude oil prices</b>								
Brent (US\$/bbl)	<b>97.23</b>	79.78	73.15	68.98	61.06	45.25	43.39	33.30
WTI (US\$/bbl)	<b>94.29</b>	77.19	70.56	66.07	57.84	42.66	40.93	27.85
Differential – WTI:WCS – Edmonton (US\$/bbl)	<b>(14.53)</b>	(14.64)	(13.58)	(11.49)	(12.47)	(9.30)	(9.09)	(11.47)
Differential – WTI:AWB – Edmonton (US\$/bbl)	<b>(16.35)</b>	(16.40)	(15.13)	(13.11)	(14.22)	(10.56)	(10.48)	(13.44)
AWB – Edmonton (US\$/bbl)	<b>77.94</b>	60.79	55.43	52.96	43.62	32.10	30.45	14.41
Differential – WTI:AWB – U.S. Gulf Coast (US\$/bbl)	<b>(5.85)</b>	(6.40)	(5.57)	(3.92)	(2.52)	(2.83)	(3.20)	(7.29)
AWB – U.S. Gulf Coast (US\$/bbl)	<b>88.44</b>	70.79	64.99	62.15	55.32	39.83	37.73	20.56
Enbridge Mainline heavy apportionment	<b>10 %</b>	21 %	53 %	46 %	48 %	22 %	9 %	13 %
<b>Condensate prices</b>								
Condensate at Edmonton (C\$/bbl)	<b>121.74</b>	99.70	87.30	81.55	73.51	55.39	50.03	30.72
Condensate at Edmonton as % of WTI	<b>102.0 %</b>	102.5 %	98.2 %	100.5 %	100.4 %	99.6 %	91.8 %	79.6 %
Condensate at Mont Belvieu, Texas (US\$/bbl)	<b>92.68</b>	76.62	68.19	61.18	56.00	38.52	33.52	17.43
Condensate at Mont Belvieu, Texas as a % of WTI	<b>98.3 %</b>	99.3 %	96.6 %	92.6 %	96.8 %	90.3 %	81.9 %	62.6 %
<b>Natural gas prices</b>								
AECO (C\$/mcf)	<b>5.16</b>	5.07	3.92	3.37	3.43	2.88	2.48	2.21
<b>Electric power prices</b>								
Alberta power pool (C\$/MWh)	<b>90.47</b>	107.25	100.27	104.73	97.25	46.05	43.75	29.94
<b>Foreign exchange rates</b>								
C\$ equivalent of 1 US\$ – average	<b>1.2661</b>	1.2600	1.2602	1.2280	1.2663	1.3031	1.3316	1.3860
C\$ equivalent of 1 US\$ – period end	<b>1.2484</b>	1.2656	1.2750	1.2405	1.2572	1.2755	1.3324	1.3616

### Crude Oil Prices

Brent crude is the primary world price benchmark for global light sweet crude oil. The price of WTI is the current benchmark for mid-continent North American crude oil prices, at Cushing Oklahoma, and its Canadian dollar equivalent is the basis for determining the royalty rate on the Corporation's bitumen sales.

Global crude oil prices strengthened in the first quarter of 2022 as a result of improved demand and declining inventories. Supply uncertainty further supported higher global crude oil prices as the Russian invasion of Ukraine and subsequent sanctions against Russia created concern for significant oil supply disruption. Although some supply relief was provided in the latter part of the quarter with the announcement of a globally coordinated release from strategic petroleum reserves, supply and demand fundamentals remain tight with the OPEC+ group maintaining its planned production increases.

WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. WCS typically trades at a differential below the WTI benchmark price and can be impacted by apportionment levels on the Enbridge Mainline system. The WCS benchmark at Edmonton reflects heavy oil prices at Hardisty, Alberta.



The Corporation sells AWB, an oil similar to WCS, but generally priced at a discount to the WCS benchmark at Edmonton, with the discount dependent on the quality difference between AWB and WCS and the supply/demand fundamentals for oil in Western Canada. AWB is also sold at the USGC and is sold at a discount or premium to WTI dependent on the supply/demand fundamentals for oil in the USGC region.

#### Condensate Prices

In order to facilitate pipeline transportation of bitumen, the Corporation uses condensate as diluent for blending with the Corporation's bitumen. The price of condensate generally correlates with the price of WTI. The Corporation sources its condensate from both the Edmonton area and the USGC, where pricing is generally lower. The Corporation has committed diluent purchases of 20,000 barrels per day at the USGC reference benchmark pricing at Mont Belvieu, Texas. Generally, condensate pricing strengthened along with the broader strengthening in petroleum pricing during the first quarter of 2022.

#### Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, used as fuel to generate steam for the thermal production process and to create steam and electricity from the Corporation's cogeneration facilities. Global natural gas prices have surged during the last six months after lower availability of renewable wind power in the summer of 2021, the closure of nuclear plants in Germany and lower Russian exports led to increased reliance on natural gas, which resulted in record low storage levels. Russia's invasion of Ukraine has driven prices even higher due to Europe's reliance on natural gas from Russia. As a result, U.S. exports have surged to record levels on the back of strong international demand and surging prices. As a result, the AECO natural gas price increased approximately 50% during the three months ended March 31, 2022 compared to the same period of 2021.

#### Electric Power Prices

Electric power prices impact the price that the Corporation receives on the sale of surplus power from the Corporation's cogeneration facilities. The Alberta power pool price decreased slightly during the three months ended March 31, 2022 compared to the same period of 2021 primarily as a result of less extreme winter conditions.

## 9. OTHER OPERATING RESULTS

#### General and Administrative

	Three months ended March 31	
<i>(\$millions, except as indicated)</i>	2022	2021
General and administrative	\$ 14	\$ 14
General and administrative expense per barrel of production	\$ 1.61	\$ 1.77

G&A expense during the three months ended March 31, 2022 was in line with the same period of 2021.

#### Depletion and Depreciation

	Three months ended March 31	
<i>(\$millions, except as indicated)</i>	2022	2021
Depletion and depreciation expense	\$ 124	\$ 108
Depletion and depreciation expense per barrel of production	\$ 13.58	\$ 13.15

Total depletion and depreciation expense increased during the three months ended March 31, 2022, compared to the same period of 2021, primarily due to the increase in production as well as higher average future development costs.

## Commodity Risk Management Gain (Loss), Net

From time to time, the Corporation enters into financial commodity risk management contracts to increase the predictability of the Corporation's cash flow by managing commodity price volatility. All financial commodity risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss). The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes.

Realized gains or losses on financial commodity risk management contracts are the result of contract settlements during the period. Unrealized gains or losses on financial commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.

The Corporation has not entered into any WTI or WTI:WCS differential commodity risk management contracts for 2022.

(\$millions)	Three months ended March 31	
	2022	2021
<b>Realized gain (loss) on:</b>		
Crude oil contracts <sup>(1)</sup>	\$ —	\$ (81)
Condensate contracts <sup>(2)</sup>	—	11
Natural gas contracts <sup>(3)</sup>	1	1
<b>Realized commodity risk management gain (loss)</b>	<b>\$ 1</b>	<b>\$ (69)</b>
<b>Unrealized gain (loss) on:</b>		
Crude oil contracts <sup>(1)</sup>	\$ —	\$ (86)
Condensate contracts <sup>(2)</sup>	—	(6)
Natural gas contracts <sup>(3)</sup>	4	4
<b>Unrealized commodity risk management gain (loss)</b>	<b>\$ 4</b>	<b>\$ (88)</b>
<b>Commodity risk management gain (loss)</b>	<b>\$ 5</b>	<b>\$ (157)</b>

(1) Includes WTI fixed price contracts, WTI enhanced fixed price contracts with sold put options and WTI:WCS fixed differential contracts.

(2) Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas relative to WTI.

(3) Relates to contracts which fix the AECO price on natural gas purchases.

For the three months ended March 31, 2022, the Corporation recognized a \$5 million net gain from commodity risk management compared to a \$157 million net loss from commodity risk management during the same period of 2021 primarily due to the fact that the Corporation no longer holds any crude oil commodity risk management contracts.

The realized commodity risk management gain (loss) represents actual contract settlements over the periods presented. The following table provides further details regarding the realized commodity risk management gain (loss):

(US\$/bbl)	Three months ended March 31	
	2022	2021
<b>WTI fixed price contracts<sup>(1)(2)</sup>:</b>		
Average fixed price	\$ —	\$ 46.96
Average settlement price	—	57.82
Gain (loss) on WTI fixed price contracts	\$ —	\$ (10.86)
<b>WTI:WCS fixed differential contracts:</b>		
Average fixed differential	\$ —	\$ (13.46)
Average settlement differential	—	(11.46)
Gain (loss) on WTI:WCS fixed differential contracts	\$ —	\$ (2.00)
<b>Condensate purchase contracts:</b>		
Average fixed differential <sup>(3)</sup>	\$ (11.30)	\$ (10.37)
Average settlement differential	(1.61)	(1.84)
Gain (loss) on condensate purchase contracts	\$ 9.69	\$ 8.53
<b>(C\$/GJ)</b>		
<b>Natural gas purchase contracts:</b>		
Average fixed price	\$ 2.50	\$ 2.61
Average settlement price	4.49	2.95
Gain (loss) on natural gas purchase contracts	\$ 1.99	\$ 0.34

(1) Includes WTI enhanced fixed price contracts with sold put options.

(2) Incremental to these WTI fixed price contracts, the Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months, the gains and losses on which are not reflected in this table.

(3) Condensate purchase contracts either fix the WTI:condensate differential at Mont Belvieu, Texas relative to WTI or fix the condensate price as a % of WTI.

### Stock-based Compensation

(\$millions)	Three months ended March 31	
	2022	2021
Cash-settled expense	\$ 44	\$ 19
Equity-settled expense	4	2
Equity price risk management gain <sup>(1)</sup>	(42)	(19)
Stock-based compensation expense (recovery)	\$ 6	\$ 2

(1) Relates to financial derivatives entered into to manage the Corporation's exposure to cash-settled restricted share units ("RSUs") and performance share units ("PSUs") vesting in 2021, 2022 and 2023 granted under the Corporation's stock-based compensation plans. Amounts are unrealized until vesting of the related units occurs. See section 11 "Risk Management" of this MD&A for further details.

The increase in cash-settled expense was primarily due to the increase in the Corporation's share price. The Corporation's common share price increased to \$17.07 per share as at March 31, 2022, from its value of \$11.70 per share as at December 31, 2021.

The equity price risk management gain is driven by the change in the Corporation's common share price relative to the notional value of the instruments. For the three months ended March 31, 2022, an equity price risk management gain of \$42 million was recognized on the increase in share price during the period compared to a gain of \$19 million during the same period of 2021.

## Foreign Exchange Gain (Loss), Net

(\$millions)	Three months ended March 31	
	2022	2021
Unrealized foreign exchange gain (loss) on:		
Long-term debt	\$ 31	\$ 48
Foreign currency risk management contracts	7	—
US\$ denominated cash and cash equivalents	(9)	(5)
Unrealized net gain (loss) on foreign exchange	29	43
Realized gain (loss) on foreign exchange	(1)	—
Foreign exchange gain (loss), net	\$ 28	\$ 43
<b>C\$ equivalent of 1 US\$</b>		
Beginning of period	1.2656	1.2755
End of period	1.2484	1.2572

The Corporation's foreign exchange gain (loss) is driven by fluctuations in the U.S. dollar to Canadian dollar exchange rate. The primary driver of the Corporation's foreign exchange gain (loss) is the Corporation's long-term debt which is denominated in U.S. dollars.

For the three months ended March 31, 2022, the Corporation recognized an unrealized foreign exchange gain of \$29 million compared to a gain of \$43 million during the same period of 2021. The Canadian dollar strengthened relative to the U.S. dollar by 1% during both periods but the unrealized gain during the three months ended March 31, 2022 was lower compared to the same period of 2021 primarily due to the decrease in U.S. dollar denominated long-term debt.

## Net Finance Expense

(\$millions)	Three months ended March 31	
	2022	2021
Interest expense on long-term debt	\$ 47	\$ 58
Interest expense on lease liabilities	6	6
Net interest expense	53	64
Accretion on provisions	2	2
Net finance expense	\$ 55	\$ 66
Average effective interest rate	6.7%	6.8%

Interest expense on long-term debt decreased during the three months ended March 31, 2022 compared to the same period of 2021 primarily as a result of the US\$100 million debt redemption on August 23, 2021 and the US\$225 million debt redemption on January 18, 2022 as well as the refinancing of US\$600 million of senior unsecured notes on February 2, 2021 at a rate of 5.875% compared to the previous rate of 7.0%.

## Income Tax

(\$millions)	Three months ended March 31	
	2022	2021
Earnings (loss) before income taxes	\$ 466	\$ (36)
Effective tax rate	22.3 %	52.8 %
Income tax expense (recovery)	\$ 104	\$ (19)

As at March 31, 2022, the Corporation had approximately \$6.7 billion of available Canadian tax pools, including \$5.1 billion of non-capital losses and \$0.4 billion of capital losses, and recognized a deferred income tax asset of \$192 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

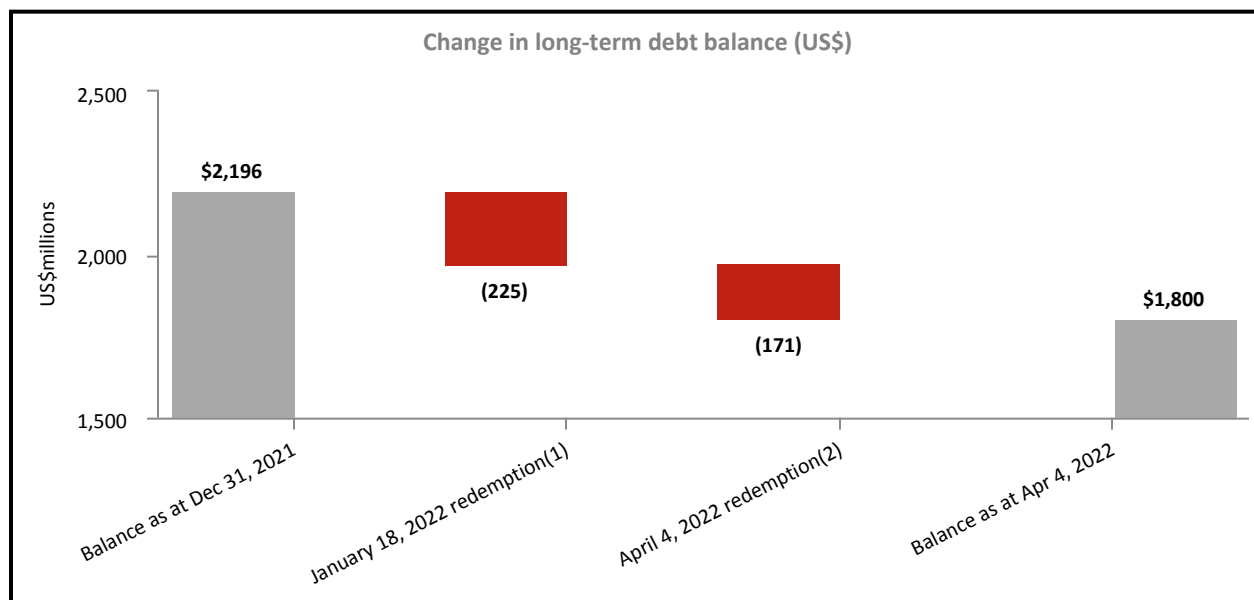
The effective tax rate for the three months ended March 31, 2022 differed from the Canadian statutory rate of 23% primarily due to the tax effect of foreign exchange gains and losses on the Corporation's long-term debt which is denominated in U.S. dollars.

## 10. LIQUIDITY AND CAPITAL RESOURCES

(\$millions)	March 31, 2022	December 31, 2021
<b>Second Lien:</b>		
6.50% senior secured second lien notes (March 31, 2022 - US\$171 million; fully redeemed April 4, 2022; December 31, 2021 - US\$396 million)	\$ 214	\$ 501
<b>Unsecured:</b>		
7.125% senior unsecured notes (March 31, 2022 - US\$1.2 billion; due 2027; December 31, 2021 - US\$1.2 billion)	1,498	1,519
5.875% senior unsecured notes (March 31, 2022 - US\$600 million; due 2029; December 31, 2021 - US\$600 million)	749	759
Debt redemption premium	4	8
Unamortized deferred debt discount and debt issue costs	(25)	(25)
Current and long-term debt	2,440	2,762
Cash and cash equivalents	(290)	(361)
Net debt - C\$ <sup>(1)</sup>	\$ 2,150	\$ 2,401
Net debt - US\$ <sup>(1)</sup>	\$ 1,722	\$ 1,897

(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 18 of the interim consolidated financial statements.

The Corporation redeemed and announced further redemptions of its long-term debt as noted below:



(1) Redemption price of 101.625% plus accrued and unpaid interest on the 6.50% senior secured second lien notes.

(2) Redemption price of 101.625% plus accrued and unpaid interest on the remaining 6.50% senior secured second lien notes.

The Corporation's cash and cash equivalents balance was \$290 million as at March 31, 2022 compared to \$361 million as at December 31, 2021. Refer to the "Cash Flow Summary" section for further details.

The Corporation has total available credit under two facilities of \$1.3 billion, comprised of \$800 million under the revolving credit facility and \$500 million under a letter of credit facility guaranteed by Export Development Canada ("EDC Facility"). Letters of credit under the EDC Facility do not consume capacity of the revolving credit facility. The revolving credit facility and the EDC Facility have a maturity date of July 30, 2024. The revolving credit facility, EDC Facility and senior secured second lien notes are secured by substantially all the assets of the Corporation.

Meeting current and future obligations while navigating the uncertainty associated with commodity market volatility continues to be supported by the Corporation's financial framework, including credit risk management policies minimizing credit exposure on sales to primarily investment grade customers in the energy industry. After the April 2022 debt redemption noted above, the Corporation's earliest maturing long-term debt is approximately five years out, represented by US\$1.2 billion of senior unsecured notes due February 2027. Additionally, the Corporation's modified covenant-lite \$800 million revolving credit facility has no financial maintenance covenant unless drawn in excess of \$400 million. If drawn in excess of \$400 million, the Corporation is required to maintain a quarterly first lien net leverage ratio (first lien net debt to last twelve-month EBITDA) of 3.5 or less. Under the Corporation's credit facility, first lien net debt is calculated as debt under the credit facility plus other debt that is secured on a *pari passu* basis with the credit facility, less cash-on-hand. None of the Corporation's outstanding long-term debt contain financial maintenance covenants and none are secured on a *pari passu* basis with the credit facility.

As at March 31, 2022, the Corporation had \$794 million of unutilized capacity under the \$800 million revolving credit facility and the Corporation had \$108 million of unutilized capacity under the \$500 million EDC Facility. A letter of credit of \$15 million was issued under the revolving credit facility during the three months ended March 31, 2020. A letter of credit of \$6 million remains outstanding under the revolving credit facility as at March 31, 2022. Letters of credit issued under the revolving credit facility are not included in first lien net debt for purposes of calculating the first lien net leverage ratio.

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary. The Corporation's cash

flow and the development of projects are dependent on factors discussed in the "RISK FACTORS" section of this MD&A.

### Cash Flow Summary

(\$millions)	Three months ended March 31	
	2022	2021
Net cash provided by (used in):		
Operating activities	\$ 317	\$ 12
Investing activities	(88)	(49)
Financing activities	(291)	(17)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	(9)	(6)
Change in cash and cash equivalents	\$ (71)	\$ (60)

### Cash Flow – Operating Activities

Net cash provided by operating activities for the three months ended March 31, 2022 increased compared to the same period of 2021, primarily due to higher benchmark crude oil prices as well as the elimination of crude oil commodity risk management contracts that were in place in the first quarter of 2021.

### Cash Flow – Investing Activities

Net cash used in investing activities increased during the three months ended March 31, 2022 compared to the same period of 2021 reflecting increased capital spending over the period.

### Cash Flow – Financing Activities

Net cash used in financing activities for the three months ended March 31, 2022 increased compared to the same period of 2021, primarily due to the debt redemption during the three months ended March 31, 2022.

## 11. RISK MANAGEMENT

### Commodity Price Risk Management

To mitigate the Corporation's exposure to fluctuations in commodity prices, the Corporation periodically enters into financial commodity risk management contracts to partially manage its exposure on blend sales, condensate purchases, natural gas purchases and power sales. The Corporation also periodically enters into physical delivery contracts which are not considered financial instruments and therefore no asset or liability has been recognized in the Consolidated Balance Sheet related to these contracts. The impact of realized physical delivery contract prices is included in the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss) and in cash operating netback.

The Corporation had the following financial commodity risk management contracts relating to condensate purchases and natural gas purchases outstanding as at March 31, 2022:

As at March 31, 2022			
<b>Condensate Purchase Contracts</b>	<b>Volumes (bbls/d)</b>	<b>Term</b>	<b>Average Price (US\$/bbl)</b>
WTI:Mont Belvieu Fixed Differential	200	Apr 1, 2022 - Dec 31, 2022	\$(11.30)
<b>Natural Gas Purchase Contracts</b>	<b>Volumes (GJ/d)</b>	<b>Term</b>	<b>Average Price (C\$/GJ)</b>
AECO Fixed Price	5,000	Apr 1, 2022 - Dec 31, 2023	\$2.50

## Equity Price Risk Management

In 2020, the Corporation entered into financial equity price risk management contracts to increase the predictability of the Corporation's cash flow by managing share price volatility. Equity price risk is the risk that changes in the Corporation's own share price impact earnings and cash flows. Earnings, funds flow from operating activities and adjusted funds flow are impacted when outstanding cash-settled RSUs and PSUs, issued under the Corporation's stock-based compensation plans, are revalued each period based on the Corporation's share price and the revaluation is recognized in stock-based compensation expense. Net cash provided by (used in) operating activities is impacted when these stock-based compensation units are ultimately settled. The Corporation entered into these equity price risk management contracts in March 2020 to manage its exposure on cash-settled RSUs and PSUs vesting between April 1, 2021 and April 1, 2023. Equity price risk management (gain) loss is recognized in stock-based compensation expense on the statement of earnings (loss), the unrealized asset (liability) is included in risk management on the balance sheet and the realized asset is included in trade receivables and other on the balance sheet.

(\$millions)	Three months ended March 31	
	2022	2021
Unrealized equity price risk management (gain) loss	\$ 4	\$ (11)
Realized equity price risk management (gain) loss	(46)	(8)
Equity price risk management (gain) loss	\$ (42)	\$ (19)

## 12. SHARES OUTSTANDING

As at March 31, 2022, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	Units
Common shares	307.6
Convertible securities	
Stock options <sup>(1)</sup>	1.6
Equity-settled RSUs and PSUs	6.7

(1) 1.4 million stock options were exercisable as at March 31, 2022.

As at April 29, 2022, the Corporation had 310.6 million common shares, 1.5 million stock options and 5.2 million equity-settled RSUs and equity-settled PSUs outstanding, and 1.5 million stock options exercisable.

## 13. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

### Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations as at March 31, 2022. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities, the senior secured second lien notes, and the senior unsecured notes may be retired earlier due to mandatory or discretionary repayments or redemptions.



(\$millions)	2022	2023	2024	2025	2026	Thereafter	Total
<b>Commitments:</b>							
Transportation and storage <sup>(1)</sup>	\$ 302	\$ 413	\$ 440	\$ 416	\$ 378	\$ 5,401	\$ 7,350
Diluent purchases	130	28	—	—	—	—	158
Other operating commitments	12	16	14	13	13	23	91
Variable office lease costs	3	5	5	5	5	22	45
Capital commitments	21	—	—	—	—	—	21
<b>Total Commitments</b>	<b>468</b>	<b>462</b>	<b>459</b>	<b>434</b>	<b>396</b>	<b>5,446</b>	<b>7,665</b>
<b>Other Obligations:</b>							
Lease obligations	33	38	37	29	29	462	628
Current and long-term debt <sup>(2)</sup>	214	—	—	—	—	2,247	2,461
Interest on long-term debt <sup>(2)</sup>	113	151	151	151	151	106	823
Decommissioning obligation <sup>(3)</sup>	3	6	5	5	5	763	787
<b>Total Commitments and Obligations</b>	<b>\$ 831</b>	<b>\$ 657</b>	<b>\$ 652</b>	<b>\$ 619</b>	<b>\$ 581</b>	<b>\$ 9,024</b>	<b>\$ 12,364</b>

(1) This represents transportation and storage commitments from 2022 to 2048, including pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet.

(2) This represents the scheduled principal repayments of the senior secured second lien notes, the senior unsecured notes, and associated interest payments based on interest and foreign exchange rates in effect on March 31, 2022.

(3) This represents the undiscounted future obligations associated with the decommissioning of the Corporation's assets.

### Contingencies

The Corporation is involved in various legal claims associated with the normal course of operations. The Corporation believes that any liabilities that may arise pertaining to such matters would not have a material impact on its financial position.

## 14. NON-GAAP AND OTHER FINANCIAL MEASURES

Certain financial measures in this MD&A are non-GAAP financial measures or ratios, supplementary financial measures and capital management measures. These measures are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP and other financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

### Adjusted Funds Flow and Free Cash Flow

Adjusted funds flow and free cash flow are capital management measures and are defined in the Corporation's annual financial statements. Adjusted funds flow and free cash flow are presented to assist management and investors in analyzing operating performance and cash flow generating ability. Funds flow from operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as funds flow from operating activities excluding items not considered part of ordinary continuing operating results. By excluding changes in non-recurring adjustments from cash flows, the adjusted funds flow measure provides a meaningful metric for management and investors by establishing a clear link between the Corporation's cash flows and the cash operating netback. Free cash flow is presented to assist management and investors in analyzing performance by the Corporation as a measure of financial liquidity and the capacity of the business to repay debt and return capital to shareholders. Free cash flow is calculated as adjusted funds flow less capital expenditures.

The following table reconciles funds flow from operating activities to adjusted funds flow to free cash flow:

(\$millions)	Three months ended March 31	
	2022	2021
Funds flow from operating activities	\$ 587	\$ 121
Adjustments:		
Payments on onerous contract	—	6
Adjusted funds flow	587	127
Capital expenditures	(88)	(70)
Free cash flow	\$ 499	\$ 57

### Net Debt

Net debt is a capital management measure and is defined in the Corporation's annual financial statements. Net debt is an important measure used by management to analyze leverage and liquidity. Net debt is calculated as long-term debt plus current portion of long-term debt less cash and cash equivalents.

The following table reconciles the Corporation's current and long-term debt to net debt:

As at	March 31, 2022	December 31, 2021
Long-term debt	\$ 2,226	\$ 2,477
Current portion of long-term debt	214	285
Cash and cash equivalents	(290)	(361)
Net debt - C\$	\$ 2,150	\$ 2,401
Net debt - US\$	\$ 1,722	\$ 1,897

### Cash Operating Netback

Cash operating netback is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. Its terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Cash operating netback is a financial measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to generate cash flow for debt repayment, capital expenditures, or other uses. The per barrel calculation of cash operating netback is based on bitumen sales volume.

Revenues, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to cash operating netback. A reconciliation from revenues to cash operating netback has been provided below:

(\$millions)	Three months ended March 31	
	2022	2021
Revenues	\$ 1,531	\$ 914
Diluent expense	(517)	(296)
Transportation and storage expense	(118)	(93)
Purchased product	(160)	(185)
Operating expenses	(104)	(66)
Cash operating netback before realized commodity risk management	632	274
Realized gain (loss) on commodity risk management	1	(69)
Cash operating netback	\$ 633	\$ 205

## Blend Sales and Bitumen Realization

Blend sales and bitumen realization are non-GAAP financial measures, or ratios when expressed on a per barrel basis, and are used as a measure of the Corporation's marketing strategy by isolating petroleum revenue and costs associated with its produced and purchased products and excludes royalties. Their terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Blend sales per barrel are based on blend sales volumes and bitumen realization per barrel is based on bitumen sales volumes.

Petroleum revenue, net of royalties, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to blend sales and bitumen realization. A reconciliation from petroleum revenue, net of royalties to blend sales and bitumen realization has been provided below:

	Three months ended March 31			
	2022		2021	
<i>(\$millions, except as indicated)</i>	\$/bbl		\$/bbl	
Petroleum revenue, net of royalties	\$	1,507	\$	886
Royalties		47		7
Petroleum revenue		1,554		893
Purchased product		(160)		(185)
Blend sales		1,394	\$	105.79
Diluent expense		(517)		(8.51)
Bitumen realization	\$	877	\$	97.28
			\$	412
			\$	52.34

## Transportation and Storage Expense net of Transportation Revenue

Transportation and storage expense net of transportation revenue is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. Its terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Per barrel amounts are based on bitumen sales volumes.

It is used as a measure of the Corporation's marketing strategy by focusing on maximizing the realized AWB sales price after transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access. Per barrel amounts are based on bitumen sales volumes.

Transportation and storage expense, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss).

Other revenue, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to transportation revenue. A reconciliation from other revenue to transportation revenue has been provided below.

	Three months ended March 31							
	2022		2021					
<i>(\$millions, except as indicated)</i>	\$/bbl		\$/bbl					
Transportation and storage expense	\$	(118)	\$	(13.12)	\$	(93)	\$	(11.83)
Other revenue	\$	24	\$	28				
Less power revenue		(23)		(25)				
Transportation revenue	\$	1	\$	0.15	\$	3	\$	0.42
Transportation and storage expense net of transportation revenue	\$	(117)	\$	(12.97)	\$	(90)	\$	(11.41)

#### Operating Expenses net of Power Revenue

Operating expenses net of power revenue is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. Its terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. Per barrel amounts are based on bitumen sales volumes.

It is used as a measure of the Corporation's cost to operate its facilities at the Christina Lake project after factoring in the benefits from selling excess power to offset energy costs.

Non-energy operating costs and energy operating costs are supplementary financial measures as they represent portions of operating expenses. Non-energy operating costs relate to production-related operating activities and energy operating costs reflect the cost of natural gas used as fuel to generate steam and power. Per barrel amounts are based on bitumen sales volumes.

Operating expenses is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss). Other revenue, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to power revenue. A reconciliation from other revenue to power revenue has been provided below.

	Three months ended March 31							
	2022		2021					
<i>(\$millions, except as indicated)</i>	\$/bbl		\$/bbl					
Non-energy operating costs	\$	(43)	\$	(4.74)	\$	(34)	\$	(4.05)
Energy operating costs		(61)		(6.80)		(32)		(4.34)
Operating expenses	\$	(104)	\$	(11.54)	\$	(66)	\$	(8.39)
Other revenue	\$	24	\$	28				
Less transportation revenue		(1)		(3)				
Power revenue	\$	23	\$	2.56	\$	25	\$	3.14
Operating expenses net of power revenue	\$	(81)	\$	(8.98)	\$	(41)	\$	(5.25)

#### 15. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting policies and estimates are those estimates having a significant impact on the Corporation's financial position and operations and that require management to make judgments, assumptions and estimates in the application of IFRS. Judgments, assumptions and estimates are based on historical experience and other factors that management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgments, assumptions and estimates may be subject to change.

Detailed disclosure of the significant accounting policies and the significant accounting estimates, assumptions and judgments used by the Corporation can be found in the Corporation's annual consolidated financial statements for the year ended December 31, 2021.

## 16. RISK FACTORS

The Corporation's primary focus is on the ongoing development and operation of its thermal oil assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including among others, operational risks, risks related to economic conditions, environmental and regulatory risks, and financing risks. Many of these risks impact the oil and gas industry as a whole. Further information regarding the risk factors which may affect the Corporation is contained in the most recently filed AIF, which is available on the Corporation's website at [www.megenergy.com](http://www.megenergy.com) and is also available on the SEDAR website at [www.sedar.com](http://www.sedar.com).

## 17. DISCLOSURE CONTROLS AND PROCEDURES

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

## 18. INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The CEO and CFO are required to cause the Corporation to disclose any change in the Corporation's internal controls over financial reporting that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting. No changes in internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

It should be noted that a control system, including the Corporation's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud. In reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost/benefit relationship of possible controls and procedures.

## 19. ABBREVIATIONS

The following provides a summary of common abbreviations used in this document:

### Financial and Business Environment

<b>AECO</b>	Alberta natural gas price reference location
<b>AIF</b>	Annual Information Form
<b>AWB</b>	Access Western Blend
<b>\$ or C\$</b>	Canadian dollars
<b>DSU</b>	Deferred share units
<b>EDC</b>	Export Development Canada
<b>eMSAGP</b>	enhanced Modified Steam And Gas Push
<b>eMVAPEX</b>	enhanced Modified VAPour EXtraction
<b>ESG</b>	Environment, Social and Governance
<b>FSP</b>	Flanagan South and Seaway Pipeline
<b>GAAP</b>	Generally Accepted Accounting Principles
<b>GHG</b>	Greenhouse Gas
<b>IFRS</b>	International Financial Reporting Standards
<b>LIBOR</b>	London Interbank Offered Rate
<b>MD&amp;A</b>	Management's Discussion and Analysis
<b>PSU</b>	Performance share units
<b>RSU</b>	Restricted share units
<b>SAGD</b>	Steam-Assisted Gravity Drainage
<b>SOR</b>	Steam-oil ratio
<b>U.S.</b>	United States
<b>US\$</b>	United States dollars
<b>WCS</b>	Western Canadian Select
<b>WTI</b>	West Texas Intermediate

### Measurement

<b>bbbl</b>	barrel
<b>bbbls/d</b>	barrels per day
<b>mcf</b>	thousand cubic feet
<b>mcf/d</b>	thousand cubic feet per day
<b>MW</b>	megawatts
<b>MW/h</b>	megawatts per hour

## 20. ADVISORY

### Forward-Looking Information

This document may contain forward-looking information within the meaning of applicable Canadian securities laws. These statements relate to future events or MEG's future performance. All statements other than statements of historical fact may be forward-looking statements. This forward-looking information is intended to be identified by words such as "anticipate", "believe", "continue", "could", "drive", "expect", "estimate", "focus", "forward", "future", "guidance", "intend", "may", "on track", "outlook", "plan", "position", "potential", "priority", "project", "should", "strategy", "target", "will", "would" or similar expressions and includes statements about future outcomes.

Forward-looking statements are often, but not always, identified by such words. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. In particular, and without limiting the foregoing, this document contains forward looking statements with respect to: the Corporation's business strategy, focus and future plans; statements regarding the Corporation's estimated reserves; the Corporation's marketing strategy and marketing asset optimization strategy; the Corporation's ability to realize production growth over time at the Christina Lake Project while minimizing GHG emissions intensity through cogeneration and the application of its proprietary technologies; the ability of the Corporation to deliver on its deleveraging and shareholder return

strategy; the Corporation's expectation of accelerating debt reduction and initiating its share buyback program in the second quarter of 2022; the Corporation's continued focus on debt reduction; statements regarding incremental well capital required to allow the Corporation to fully utilize the Christina Lake central plant facility's oil processing capacity of approximately 100,000 barrels per day the Corporation's 2022 guidance, including full year 2022 production, non-energy operating costs, general and administrative costs, capital expenditures and total transportation costs; the Corporation's expectation of reaching its near-term debt target of US\$1.7 billion in the second quarter of 2022 and thereafter allocating 25% of free cash flow to share buybacks with the remaining cash flow applied to ongoing debt reduction; the Corporation's expectation of reaching its net debt-target of US\$1.2 billion in the third quarter of 2022 and thereafter allocating 50% of free cash flow to share buybacks with the remainder applied to further debt reduction until the Corporation reaches its net debt floor of US\$600 million at which time 100% of free cash flow will be returned to shareholders; the Corporation's expectation that net debt of US\$600 million implies a net debt to EBITDA multiple of 1.0 times at a long-term US\$50 per barrel WTI price; the Corporation's expectation that it will reach its net debt floor of US\$600 million in the second half of 2023; the Corporation's expectation that the announced federal investment tax credit, together with support from the Alberta government, will help advance the Oilsands Pathways to Net Zero Alliance's plan to achieve meaningful emissions reductions by 2023 and net zero emissions from oil sands operations by 2050; the Corporation's ability to sell excess power into the Alberta electrical grid to displace other power sources that have a higher carbon intensity, thereby reducing the Corporation's overall carbon footprint; the Corporation's expectations regarding its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business; and the Corporation's statements regarding its 2022 hedge book.

Forward-looking information contained in this document is based on management's expectations and assumptions regarding, among other things: future crude oil, bitumen blend, natural gas, electricity, condensate and other diluent prices, differentials, the level of apportionment on the Enbridge mainline system, transportation costs, foreign exchange rates and interest rates; the recoverability of the Corporation's reserves and contingent resources; the Corporation's ability to produce and market production of bitumen blend successfully to customers; future growth, results of operations and production levels; future capital and other expenditures; revenues, expenses and cash flow; operating costs; reliability; continued liquidity and runway to sustain operations through a prolonged market downturn; MEG's ability to reduce or increase production to desired levels, including without negative impacts to its assets; anticipated reductions in operating costs as a result of optimization and scalability of certain operations; anticipated sources of funding for operations and capital investments; plans for and results of drilling activity; the regulatory framework governing royalties, land use, taxes and environmental matters, including the timing and level of government production curtailment and federal and provincial climate change policies, in which the Corporation conducts and will conduct its business; the impact of the Corporation's response to the COVID-19 global pandemic; actions taken by OPEC+ in relation to supply management; and business prospects and opportunities. By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated.

These risks and uncertainties include, but are not limited to, risks and uncertainties related to: the oil and gas industry, for example, the securing of adequate access to markets and transportation infrastructure (including pipelines and rail) and the commitments therein; the availability of capacity on the electricity transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and revenues; health, safety and environmental risks, including public health crises, such as the COVID-19 pandemic, and any related actions taken by governments and businesses; legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws and production curtailment; the cost of compliance with current and future environmental laws, including climate change laws; risks relating to increased activism and public opposition to fossil fuels and oil sands; assumptions regarding and the volatility of commodity prices, interest rates and foreign exchange rates; commodity price, interest rate and foreign exchange rate swap contracts and/or derivative financial instruments that the Corporation may enter into from time to time to manage its risk related to such prices and rates; timing of completion, commissioning, and start-up, of the Corporation's turnarounds; the operational risks and delays in the development, exploration, production, and the capacities and performance associated with the Corporation's projects; the Corporation's ability to reduce or increase production to desired levels, including without negative impacts to its assets; the Corporation's ability to finance sustaining capital expenditures; the Corporation's ability to maintain sufficient liquidity to sustain operations through a prolonged market downturn; changes in credit ratings applicable to the Corporation or any of its securities; the Corporation's response to the COVID-19 global pandemic; the severity and duration of the COVID-19 pandemic; the potential for a temporary suspension of operations impacted by an outbreak of COVID-19; actions taken by OPEC+ in relation to supply management; the impact of the Russian invasion of Ukraine and associated sanctions

on commodity prices; the availability and cost of labour and goods and services required in the Corporation's operations, including inflationary pressures; supply chain issues including transportation delays; the cost and availability of equipment necessary to our operations; and changes in general economic, market and business conditions.

Although the Corporation believes that the assumptions used in such forward-looking information are reasonable, there can be no assurance that such assumptions will be correct. Accordingly, readers are cautioned that the actual results achieved may vary from the forward-looking information provided herein and that the variations may be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive.

Further information regarding the assumptions and risks inherent in the making of forward-looking statements can be found in the Corporation's most recently filed AIF, along with the Corporation's other public disclosure documents. Copies of the AIF and the Corporation's other public disclosure documents are available through the SEDAR website at [www.sedar.com](http://www.sedar.com).

The forward-looking information included in this document is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this document is made as of the date of this document and the Corporation assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

MEG Energy Corp. is an energy company focused on sustainable in situ thermal oil production in the southern Athabasca oil region of Alberta, Canada. The Corporation is actively developing innovative enhanced oil recovery projects that utilize SAGD extraction methods to improve the responsible economic recovery of oil as well as lower carbon emissions. MEG transports and sells its thermal oil (known as AWB) to customers throughout North America and internationally. The Corporation's common shares are listed on the Toronto Stock Exchange under the symbol "MEG".

#### **Estimates of Reserves and Resources**

For information regarding the Corporation's estimated reserves and resources, please refer to the Corporation's most recently filed AIF.

## **21. ADDITIONAL INFORMATION**

Additional information relating to the Corporation, including its AIF, is available on the Corporation's website at [www.megenergy.com](http://www.megenergy.com) and is also available on SEDAR at [www.sedar.com](http://www.sedar.com).



## 22. QUARTERLY SUMMARIES

	2022	2021				2020		
Unaudited	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
<b>FINANCIAL</b> (\$millions unless specified)								
Net earnings (loss)	362	177	54	68	(17)	16	(9)	(80)
Per share, diluted	1.15	0.57	0.17	0.22	(0.06)	0.05	(0.03)	(0.26)
Funds flow from operating activities	587	260	212	160	121	81	19	69
Adjusted funds flow <sup>(1)</sup>	587	266	239	166	127	84	26	89
Per share, diluted	1.87	0.85	0.77	0.53	0.41	0.27	0.09	0.29
Capital expenditures	88	106	84	71	70	40	35	20
Working capital	465	150	199	127	8	55	131	173
Net debt - C\$ <sup>(1)</sup>	2,150	2,401	2,559	2,661	2,798	2,798	2,981	2,976
Net debt - US\$ <sup>(1)</sup>	1,722	1,897	2,007	2,145	2,226	2,194	2,237	2,186
Shareholders' equity	4,178	3,808	3,628	3,564	3,491	3,506	3,495	3,507
<b>BUSINESS ENVIRONMENT</b>								
<b>Average Benchmark Commodity Prices:</b>								
WTI (US\$/bbl)	94.29	77.19	70.56	66.07	57.84	42.66	40.93	27.85
Differential – WTI:WCS – Edmonton (US\$/bbl)	(14.53)	(14.64)	(13.58)	(11.49)	(12.47)	(9.30)	(9.09)	(11.47)
Differential – WTI:AWB – Edmonton (US\$/bbl)	(16.35)	(16.40)	(15.13)	(13.11)	(14.22)	(10.56)	(10.48)	(13.44)
AWB – Edmonton (US\$/bbl)	77.94	60.79	55.43	52.96	43.62	32.10	30.45	14.41
Differential – WTI:AWB – U.S. Gulf Coast (US\$/bbl)	(5.85)	(6.40)	(5.57)	(3.92)	(2.52)	(2.83)	(3.20)	(7.29)
AWB – U.S. Gulf Coast (US\$/bbl)	88.44	70.79	64.99	62.15	55.32	39.83	37.73	20.56
Enbridge Mainline heavy apportionment	10 %	21 %	53 %	46 %	48 %	22 %	9 %	13 %
C\$ equivalent of 1US\$ – average	1.2661	1.2600	1.2602	1.2280	1.2663	1.3031	1.3316	1.3860
Natural gas – AECO (\$/mcf)	5.16	5.07	3.92	3.37	3.43	2.88	2.48	2.21
<b>OPERATIONAL</b> (\$/bbl unless specified)								
Blend sales, net of purchased product – bbls/d	146,382	141,280	127,546	129,474	128,236	136,623	93,479	100,980
Diluent usage – bbls/d	(46,196)	(42,386)	(35,295)	(39,494)	(40,938)	(40,892)	(25,910)	(30,583)
Bitumen sales – bbls/d	100,186	98,894	92,251	89,980	87,298	95,731	67,569	70,397
Bitumen production – bbls/d	101,128	100,698	91,506	91,803	90,842	91,030	71,516	75,687
Steam-oil ratio (SOR)	2.43	2.42	2.56	2.39	2.37	2.31	2.36	2.32
Blend sales <sup>(2)</sup>	105.79	82.43	74.54	69.27	61.28	45.75	45.44	20.96
Diluent expense	(8.51)	(11.37)	(9.63)	(9.18)	(8.94)	(7.11)	(5.76)	(10.78)
Bitumen realization <sup>(2)</sup>	97.28	71.06	64.91	60.09	52.34	38.64	39.68	10.18
Transportation & storage expense net of transportation revenue <sup>(2)</sup>	(12.97)	(11.39)	(10.03)	(10.91)	(11.41)	(14.11)	(18.55)	(11.77)
Curtailment	—	—	—	—	—	0.03	—	—
Royalties	(5.24)	(3.54)	(2.67)	(1.71)	(0.85)	(0.23)	(0.21)	(0.05)
Non-energy operating costs <sup>(3)</sup>	(4.74)	(4.56)	(4.46)	(3.84)	(4.05)	(4.70)	(3.96)	(4.09)
Energy operating costs <sup>(3)</sup>	(6.80)	(6.22)	(4.77)	(4.27)	(4.34)	(3.73)	(3.17)	(3.00)
Power revenue	2.56	2.58	2.06	2.57	3.14	1.45	1.08	0.95
Realized gain (loss) on commodity risk management	0.12	(10.06)	(7.73)	(10.63)	(8.80)	1.31	1.71	33.62
Cash operating netback <sup>(2)</sup>	70.21	37.87	37.31	31.30	26.03	18.66	16.58	25.84
Power sales price (C\$/MWh)	91.50	95.22	82.17	88.40	93.27	46.34	39.03	28.34
Power sales (MW/h)	121	117	101	113	128	125	78	98
Average cost of diluent (\$/bbl of diluent)	124.23	108.96	99.69	90.18	80.34	62.37	60.48	45.76
Average cost of diluent as a % of WTI	104 %	112 %	112 %	111 %	110 %	112 %	111 %	119 %
Depletion and depreciation rate per bbl of production	13.58	13.63	12.78	12.99	13.15	12.64	13.33	13.55
General and administrative expense per bbl of production	1.61	1.58	1.72	1.56	1.77	1.65	1.50	1.29
<b>COMMON SHARES</b>								
Shares outstanding, end of period (000)	307,596	306,865	306,773	306,716	303,137	302,681	302,657	302,645
Common share price (\$) - close (end of period)	17.07	11.70	9.89	8.97	6.53	4.45	2.77	3.77

(1) Capital management measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

(2) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

(3) Supplementary financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

During the eight most recent quarters the following items have had a significant impact on the Corporation's quarterly results:

- significant variability in blend sales pricing primarily due to high volatility in the price of WTI which ranges from a quarterly average of US\$27.85/bbl to US\$94.29/bbl. The volatility in 2020 was driven by the impact of COVID-19 on supply and demand fundamentals. Since then we've seen a continual strengthening resulting from improved demand and declining inventories. Supply uncertainty further supported higher global crude oil prices as the February 2022 Russian invasion of Ukraine and subsequent sanctions against Russia created concern for significant oil supply disruption;
- the cost of diluent due to changes in Canadian and U.S. benchmark pricing, the timing of diluent inventory purchases and the impact of foreign exchange;
- changes in the value of the Canadian dollar relative to the U.S. dollar and its impact on blend sales prices, the cost of diluent, interest expense, and foreign exchange gains and losses associated with the Corporation's U.S. dollar denominated debt;
- timing of capital projects;
- cost reduction efforts;
- apportionment and the ability to reach USGC markets;
- fluctuations in natural gas and power pricing;
- gains and losses on risk management contracts;
- changes in depletion and depreciation expense as a result of changes in production rates, and future development costs;
- changes in the Corporation's share price and the implementation of financial equity price risk management contracts, and the resulting impact on stock-based compensation;
- planned turnaround and other maintenance activities affecting production; and
- voluntary curtailment efforts associated with uneconomic benchmark pricing environments.

## 23. ANNUAL SUMMARIES

	2021	2020	2019	2018 <sup>(1)</sup>	2017 <sup>(1)</sup>	2016 <sup>(1)</sup>	2015 <sup>(1)</sup>
<b>FINANCIAL</b> <i>(\$millions unless specified)</i>							
Net earnings (loss)	283	(357)	(62)	(119)	166	(429)	(1,170)
Per share, diluted	0.91	(1.18)	(0.21)	(0.40)	0.57	(1.90)	(5.21)
Funds flow from operating activities	753	239	741	169	343	(69)	34
Adjusted funds flow <sup>(2)</sup>	799	275	724	175	371	(63)	49
Per share, diluted	2.57	0.90	2.41	0.58	1.28	(0.28)	0.22
Capital expenditures	331	149	198	622	508	140	314
Working capital	150	55	123	290	313	96	363
Net debt - C\$ <sup>(1)</sup>	2,401	2,798	2,917	3,422	4,205	4,897	4,782
Net debt - US\$ <sup>(1)</sup>	1,897	2,194	2,250	2,508	3,359	3,647	3,455
Shareholders' equity	3,808	3,506	3,853	3,886	3,964	3,287	3,678
<b>BUSINESS ENVIRONMENT</b>							
<b>Average Benchmark Commodity Prices:</b>							
WTI (US\$/bbl)	67.91	39.40	57.03	64.77	50.95	43.33	48.80
Differential – WTI:WCS – Edmonton (US\$/bbl)	(13.04)	(12.60)	(12.76)	(26.31)	(11.98)	(13.84)	(13.52)
Differential – WTI:AWB – Edmonton (US\$/bbl)	(14.71)	(14.32)	(14.95)	(29.99)	(14.09)	(16.40)	(16.69)
AWB – Edmonton (US\$/bbl)	53.20	25.08	42.08	34.78	36.86	26.93	32.11
Differential – WTI:AWB – U.S. Gulf Coast (US\$/bbl)	(4.60)	(4.77)	(1.77)	(6.68)	(7.61)	(11.53)	(8.53)
AWB - U.S. Gulf Coast (US\$/bbl)	63.31	34.63	55.26	58.09	43.34	31.80	40.27
Enbridge Mainline heavy apportionment	42 %	24 %	43 %	41 %	20 %	12 %	31 %
C\$ equivalent of 1US\$ – average	1.2536	1.3413	1.3269	1.2962	1.2980	1.3256	1.2788
Natural gas – AECO (\$/mcf)	3.95	2.43	1.92	1.62	2.29	2.25	2.71
<b>OPERATIONAL</b> <b>(\$/bbl unless specified)</b>							
Blend sales, net of purchased product – bbls/d	131,659	118,347	134,223	125,368	115,766	116,586	117,132
Diluent usage – bbls/d	(39,521)	(35,626)	(40,637)	(38,317)	(35,766)	(36,159)	(36,167)
Bitumen sales – bbls/d	92,138	82,721	93,586	87,051	80,000	80,427	80,965
Bitumen production – bbls/d	93,733	82,441	93,082	87,731	80,774	81,245	80,025
Steam-oil ratio (SOR)	2.43	2.32	2.22	2.19	2.31	2.29	2.47
Blend sales <sup>(3)</sup>	72.20	37.65	61.29	53.47	51.39	38.19	42.14
Diluent expense	(9.73)	(10.42)	(8.08)	(16.78)	(9.36)	(10.28)	(11.43)
Bitumen realization <sup>(3)</sup>	62.47	27.23	53.21	36.69	42.03	27.91	30.71
Transportation & storage expense net of transportation revenue <sup>(3)</sup>	(10.93)	(12.92)	(10.84)	(8.42)	(6.89)	(6.46)	(4.82)
Curtailement	—	0.06	(0.37)	—	—	—	—
Royalties	(2.25)	(0.31)	(1.30)	(1.20)	(0.77)	(0.29)	(0.70)
Non-energy operating costs <sup>(4)</sup>	(4.24)	(4.38)	(4.61)	(4.62)	(4.62)	(5.62)	(6.54)
Energy operating costs <sup>(4)</sup>	(4.94)	(3.29)	(2.38)	(1.98)	(2.98)	(3.01)	(3.84)
Power revenue	2.58	1.49	1.75	1.51	0.76	0.64	0.99
Realized gain (loss) on commodity risk management	(9.32)	11.34	(3.31)	(4.37)	(0.39)	0.08	—
Cash operating netback <sup>(3)</sup>	33.37	19.22	32.15	17.61	27.14	13.25	15.80
Power sales price (C\$/MWh)	90.10	47.81	56.70	47.87	21.49	18.74	27.48
Power sales (MW/h)	115	108	121	114	118	115	121
Average cost of diluent (\$/bbl of diluent)	94.88	61.86	79.89	91.60	72.32	61.06	67.72
Average cost of diluent as a % of WTI	111 %	117 %	106 %	109 %	109 %	106 %	109 %
Depletion and depreciation rate per bbl of production	13.15	13.60	20.90	14.12	16.13	16.81	16.00
General and administrative expense per bbl of production	1.65	1.62	1.99	2.58	2.94	3.24	4.06
<b>COMMON SHARES</b>							
Shares outstanding, end of period (000)	306,865	302,681	299,508	296,841	294,104	226,467	224,997
Common share price (\$) - close (end of period)	11.70	4.45	7.39	7.71	5.14	9.23	8.02

(1) The Corporation adopted IFRS 16 Leases, effective January 1, 2019, therefore prior periods have not been restated.

(2) Capital management measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

(3) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

(4) Supplementary financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.



## INTERIM FINANCIAL STATEMENTS

### Consolidated Balance Sheet (Unaudited, expressed in millions of Canadian dollars)

As at	Note	March 31, 2022	December 31, 2021
<b>Assets</b>			
Current assets			
Cash and cash equivalents	15	\$ 290	\$ 361
Trade receivables and other	3	679	496
Inventories		226	157
Risk management	17	76	36
		1,271	1,050
Non-current assets			
Property, plant and equipment	4	5,852	5,878
Exploration and evaluation assets	5	126	126
Other assets	6	201	202
Risk management	17	2	41
Deferred income tax asset	14	192	296
<b>Total assets</b>		<b>\$ 7,644</b>	<b>\$ 7,593</b>
<b>Liabilities</b>			
Current liabilities			
Accounts payable and accrued liabilities		\$ 535	\$ 500
Interest payable		29	80
Current portion of long-term debt	7	214	285
Current portion of provisions and other liabilities	8	28	27
Risk management	17	—	7
		806	899
Non-current liabilities			
Long-term debt	7	2,226	2,477
Provisions and other liabilities	8	434	409
<b>Total liabilities</b>		<b>3,466</b>	<b>3,785</b>
<b>Shareholders' equity</b>			
Share capital	9	5,496	5,486
Contributed surplus		172	172
Deficit		(1,513)	(1,875)
Accumulated other comprehensive income		23	25
<b>Total shareholders' equity</b>		<b>4,178</b>	<b>3,808</b>
<b>Total liabilities and shareholders' equity</b>		<b>\$ 7,644</b>	<b>\$ 7,593</b>

Commitments and contingencies (Note 19)

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

**Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss)**  
(Unaudited, expressed in millions of Canadian dollars, except per share amounts)

<b>Three Months Ended March 31</b>	<b>Note</b>	<b>2022</b>	<b>2021</b>
<b>Revenues</b>			
Petroleum revenue, net of royalties	11	\$ 1,507	\$ 886
Other revenue	11	24	28
Revenues		1,531	914
<b>Expenses</b>			
Diluent expense		517	296
Transportation and storage expense		118	93
Operating expenses		104	66
Inventory impairment		—	6
Purchased product		160	185
Depletion and depreciation	4, 6	124	108
General and administrative		14	14
Stock-based compensation	10	6	2
Net finance expense	13	55	66
Commodity risk management (gain) loss, net	17	(5)	157
Foreign exchange (gain) loss, net	12	(28)	(43)
Earnings (loss) before income taxes		466	(36)
Income tax expense (recovery)	14	104	(19)
Net earnings (loss)		362	(17)
Other comprehensive income (loss), net of tax			
Items that may be reclassified to profit or loss:			
Foreign currency translation adjustment		(2)	(3)
Comprehensive income (loss)		\$ 360	\$ (20)
<b>Net earnings (loss) per common share</b>			
Basic	16	\$ 1.18	\$ (0.06)
Diluted	16	\$ 1.15	\$ (0.06)

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

**Consolidated Statement of Changes in Shareholders' Equity**  
(Unaudited, expressed in millions of Canadian dollars)

	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2021	\$ 5,486	\$ 172	\$ (1,875)	\$ 25	\$ 3,808
Stock-based compensation	—	3	—	—	3
Stock options exercised	10	(3)	—	—	7
Comprehensive income (loss)	—	—	362	(2)	360
<b>Balance as at March 31, 2022</b>	<b>\$ 5,496</b>	<b>\$ 172</b>	<b>\$ (1,513)</b>	<b>\$ 23</b>	<b>\$ 4,178</b>
Balance as at December 31, 2020	\$ 5,460	\$ 177	\$ (2,158)	\$ 27	\$ 3,506
Stock-based compensation	—	2	—	—	2
Stock options exercised	4	(1)	—	—	3
Comprehensive income (loss)	—	—	(17)	(3)	(20)
<b>Balance as at March 31, 2021</b>	<b>\$ 5,464</b>	<b>\$ 178</b>	<b>\$ (2,175)</b>	<b>\$ 24</b>	<b>\$ 3,491</b>

*The accompanying notes are an integral part of these Interim Consolidated Financial Statements.*

**Consolidated Statement of Cash Flow**  
(Unaudited, expressed in millions of Canadian dollars)

Three Months Ended March 31	Note	2022	2021
<b>Cash provided by (used in):</b>			
Operating activities			
Net earnings (loss)		\$ 362	\$ (17)
Adjustments for:			
Deferred income tax expense (recovery)	14	104	(19)
Inventory impairment		—	6
Depletion and depreciation	4, 6	124	108
Stock-based compensation	10	8	(8)
Unrealized net (gain) loss on foreign exchange	12	(29)	(43)
Unrealized net (gain) loss on commodity risk management	17	(4)	88
Amortization of debt discount and debt issue costs		2	2
Other		1	1
Decommissioning expenditures	8	(2)	(2)
Onerous contracts expense (payments)		—	(6)
Net change in long-term incentive compensation liability		21	11
Funds flow from operating activities		587	121
Net change in non-cash working capital items	15	(270)	(109)
<b>Net cash provided by (used in) operating activities</b>		<b>317</b>	<b>12</b>
Investing activities			
Capital expenditures	4	(88)	(70)
Other		(1)	—
Net change in non-cash working capital items	15	1	21
<b>Net cash provided by (used in) investing activities</b>		<b>(88)</b>	<b>(49)</b>
Financing activities			
Issuance of senior unsecured notes		—	769
Repayment and redemption of long-term debt	7	(288)	(763)
Debt redemption premium and refinancing costs	7	(5)	(19)
Issue of shares, net of issue costs		7	2
Receipts on leased assets	15	1	1
Payments on leased liabilities	15	(6)	(7)
<b>Net cash provided by (used in) financing activities</b>		<b>(291)</b>	<b>(17)</b>
<b>Effect of exchange rate changes on cash and cash equivalents held in foreign currency</b>		<b>(9)</b>	<b>(6)</b>
Change in cash and cash equivalents		(71)	(60)
Cash and cash equivalents, beginning of period		361	114
Cash and cash equivalents, end of period		\$ 290	\$ 54

*The accompanying notes are an integral part of these Interim Consolidated Financial Statements.*

## NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Period ended March 31, 2022

All amounts are expressed in millions of Canadian dollars unless otherwise noted.

(Unaudited)

### 1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange under the symbol "MEG". The Corporation owns a 100% interest in over 410 square miles of mineral leases in the southern Athabasca oil region of Alberta, Canada and is primarily engaged in sustainable *in situ* thermal oil production at its Christina Lake Project.

The corporate office is located at 600 – 3rd Avenue SW, Calgary, Alberta, Canada.

### 2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements ("interim consolidated financial statements") were prepared using the same accounting policies and methods as those used in the Corporation's audited consolidated financial statements for the year ended December 31, 2021. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting ("IAS 34"). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"), has been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 4 of the Corporation's audited consolidated financial statements for the year ended December 31, 2021. These interim consolidated financial statements should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2021.

These interim consolidated financial statements are presented in Canadian dollars (\$ or C\$), which is the Corporation's functional currency and were approved by the Corporation's Audit Committee on May 2, 2022.

### 3. TRADE RECEIVABLES AND OTHER

As at	March 31, 2022	December 31, 2021
Trade receivables	\$ 612	\$ 479
Realized settlement on equity price risk management contracts	46	—
Deposits and advances	18	14
Current portion of sublease receivable	3	3
	\$ 679	\$ 496



#### 4. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Right-of-use assets	Corporate assets	Total
<b>Cost</b>					
Balance as at December 31, 2021	\$ 9,611	\$ 47	\$ 286	\$ 79	\$ 10,023
Additions	88	—	—	—	88
Change in decommissioning liabilities	9	—	—	—	9
<b>Balance as at March 31, 2022</b>	<b>\$ 9,708</b>	<b>\$ 47</b>	<b>\$ 286</b>	<b>\$ 79</b>	<b>\$ 10,120</b>
<b>Accumulated depletion and depreciation</b>					
Balance as at December 31, 2021	\$ 3,998	\$ 32	\$ 61	\$ 54	\$ 4,145
Depletion and depreciation	117	—	5	1	123
<b>Balance as at March 31, 2022</b>	<b>\$ 4,115</b>	<b>\$ 32</b>	<b>\$ 66</b>	<b>\$ 55</b>	<b>\$ 4,268</b>
<b>Carrying amounts</b>					
Balance as at December 31, 2021	\$ 5,613	\$ 15	\$ 225	\$ 25	\$ 5,878
<b>Balance as at March 31, 2022</b>	<b>\$ 5,593</b>	<b>\$ 15</b>	<b>\$ 220</b>	<b>\$ 24</b>	<b>\$ 5,852</b>

As at March 31, 2022, property, plant and equipment was assessed for indicators of impairment and none were identified.

#### 5. EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation assets consist of \$126 million in exploration projects which are pending the determination of proved or probable reserves (year ended December 31, 2021 – \$126 million). These assets were assessed for impairment and no impairment has been recognized on exploration and evaluation assets.

#### 6. OTHER ASSETS

As at	March 31, 2022	December 31, 2021
Non-current pipeline linefill <sup>(a)</sup>	\$ 176	\$ 177
Finance sublease receivables	14	15
Intangible assets <sup>(b)</sup>	5	5
Prepaid transportation costs <sup>(c)</sup>	8	8
Pathways Initiative	1	—
	<b>204</b>	205
Less current portion, included in trade receivables and other	<b>(3)</b>	(3)
	<b>\$ 201</b>	\$ 202

- Non-current pipeline linefill on third-party owned pipelines is classified as a non-current asset as these transportation contracts expire between the years 2025 and 2048.
- As at March 31, 2022, intangible assets consist of software that is not an integral component of the related computer hardware. Depreciation of \$1 million was recognized for the three months ended March 31, 2022 (year ended December 31, 2021 – \$2 million).
- Prepaid transportation costs related to upgrading third-party transportation infrastructure have been capitalized and are being amortized to transportation expense over the 30-year term of the agreement.

## 7. LONG-TERM DEBT

As at	March 31, 2022	December 31, 2021
<b>Second Lien:</b>		
6.50% senior secured second lien notes (March 31, 2022 - US\$171 million; fully redeemed April 4, 2022; December 31, 2021 - US\$396 million)	\$ 214	\$ 501
<b>Unsecured:</b>		
7.125% senior unsecured notes (March 31, 2022 - US\$1.2 billion; due 2027; December 31, 2021 - US\$1.2 billion)	1,498	1,519
5.875% senior unsecured notes (March 31, 2022 - US\$600 million; due 2029; December 31, 2021 - US\$600 million)	749	759
	<b>2,461</b>	2,779
Debt redemption premium	4	8
Unamortized deferred debt discount and debt issue costs	(25)	(25)
	<b>\$ 2,440</b>	\$ 2,762
Less current portion of 6.50% senior secured second lien notes	(214)	(285)
	<b>\$ 2,226</b>	\$ 2,477

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US\$1 = C\$1.2484 (December 31, 2021 – US\$1 = C\$1.2656).

On January 18, 2022, the Corporation repaid US\$225 million (approximately C\$285 million) of the 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625%, plus accrued and unpaid interest to, but not including, the redemption date.

On March 3, 2022 the Corporation announced that it had issued a notice to redeem the remaining outstanding balance of US\$171 million (approximately C\$214 million) of the 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625%, plus accrued and unpaid interest to, but not including, the redemption date. The redemption was completed on April 4, 2022.

Both of these redemptions included prepayment options, recognized as at December 31, 2021. The Corporation is required to assess the likelihood of exercising prepayment options at each reporting date.

As at March 31, 2022, the Corporation had \$794 million of unutilized capacity under the \$800 million revolving credit facility and the Corporation had \$108 million of unutilized capacity under the \$500 million EDC Facility. A letter of credit of \$15 million was issued under the revolving credit facility during the first quarter of 2020 and \$6 million remains outstanding as at March 31, 2022.

## 8. PROVISIONS AND OTHER LIABILITIES

As at	March 31, 2022	December 31, 2021
Lease liabilities <sup>(a)</sup>	\$ 260	\$ 266
Decommissioning provision <sup>(b)</sup>	144	135
Long-term incentive compensation liability <sup>(c)</sup>	58	35
Provisions and other liabilities	<b>462</b>	436
Less current portion	(28)	(27)
Non-current portion	<b>\$ 434</b>	\$ 409

a. Lease liabilities:

As at	March 31, 2022	December 31, 2021
Balance, beginning of period	\$ 266	\$ 286
Additions	—	8
Payments	(12)	(54)
Interest expense	6	26
Balance, end of period	260	266
Less current portion	(21)	(22)
Non-current portion	\$ 239	\$ 244

The Corporation's minimum lease payments are as follows:

As at March 31	2022
Within one year	\$ 44
Later than one year but not later than five years	137
Later than five years	462
Minimum lease payments	643
Amounts representing finance charges	(383)
Net minimum lease payments	\$ 260

The Corporation has short-term leases with lease terms of twelve months or less as well as low-value leases. As these lease costs are incurred they are recognized as either general and administrative expense or operating expense depending on their nature. As at March 31, 2022, the present value of these arrangements is \$2 million (December 31, 2021 - \$2 million), using the Corporation's estimated incremental borrowing rate.

b. Decommissioning provision:

The following table presents the decommissioning provision associated with the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets:

As at	March 31, 2022	December 31, 2021
Balance, beginning of period	\$ 135	\$ 96
Changes in estimated life and estimated future cash flows	1	5
Changes in discount rates	8	29
Liabilities settled	(2)	(3)
Accretion	2	8
Balance, end of period	144	135
Less current portion	(7)	(5)
Non-current portion	\$ 137	\$ 130

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The total undiscounted amount of the estimated future cash flows to settle the decommissioning obligations is \$787 million (December 31, 2021 – \$799 million). As at March 31, 2022, the Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 8.6% (December 31, 2021 – 9.2%) and an inflation rate of 2.1% (December 31, 2021 - 2.1%). The

decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2021 - periods up to the year 2066).

c. Long-term incentive compensation liability:

As at March 31, 2022, the Corporation recognized a liability of \$127 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2021 – \$82 million). The current portion of \$69 million is included within accounts payable and accrued liabilities and \$58 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards (December 31, 2021 – \$45 million and \$37 million). The Corporation entered into equity price risk management contracts to manage its exposure on cash-settled RSUs and PSUs vesting between 2021 and 2023. Refer to Note 17 for further details.

## 9. SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares.

Changes in issued common shares are as follows:

	Three months ended March 31, 2022		Year ended December 31, 2021	
	Number of shares (thousands)	Amount	Number of shares (thousands)	Amount
Balance, beginning of year	306,865	\$ 5,486	302,681	\$ 5,460
Issued upon exercise of stock options	731	10	939	7
Issued upon vesting and release of RSUs and PSUs	—	—	3,245	19
Balance, end of period	307,596	\$ 5,496	306,865	\$ 5,486

## 10. STOCK-BASED COMPENSATION

Three months ended March 31	2022	2021
Cash-settled expense <sup>(i)</sup>	\$ 44	\$ 19
Equity-settled expense	4	2
Equity price risk management (gain) loss <sup>(ii)</sup>	(42)	(19)
Stock-based compensation	\$ 6	\$ 2

(i) Cash-settled RSUs and PSUs are accounted for as liability instruments and are measured at fair value based on the market value of the Corporation's common shares at each period end and certain estimates including a performance multiplier for PSUs. Fluctuations in the fair value are recognized during the period in which they occur.

(ii) Relates to financial derivatives entered into to manage the Corporation's exposure to cash-settled RSUs and PSUs vesting between 2021 and 2023 granted under the Corporation's stock-based compensation plans. Amounts are unrealized until vesting of the related units occurs. See note 17(d) for further details.

A \$44 million cash-settled expense was recognized during the three months ended March 31, 2022 due to the increase in the Corporation's share price, and associated increase in value of cash-settled RSUs, PSUs and DSUs compared to December 31, 2021, which translated into an increased liability at March 31, 2022, and higher expense for the three months ended March 31, 2022 compared to the prior period. As at March 31, 2022, the Corporation recognized a liability of \$127 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2021 – \$82 million). The current portion of \$69 million is included within accounts payable and accrued liabilities and \$58 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards.

## 11. REVENUES

Three months ended March 31	2022		2021	
Sales from:				
Production	\$	1,393	\$	695
Purchased product <sup>(i)</sup>		161		198
Petroleum revenue	\$	1,554	\$	893
Royalties		(47)		(7)
Petroleum revenue, net of royalties	\$	1,507	\$	886
Power revenue	\$	23	\$	25
Transportation revenue		1		3
Other revenue	\$	24	\$	28
Revenues	\$	1,531	\$	914

(i) The associated third-party purchases are included in the consolidated statement of earnings (loss) and comprehensive income (loss) under the caption "Purchased product".

### a. Disaggregation of revenue from contracts with customers

The Corporation recognizes revenue upon delivery of goods and services in the following geographic regions:

	Three months ended March 31					
	2022			2021		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	\$ 536	\$ 55	\$ 591	\$ 391	\$ —	\$ 391
United States	857	106	963	304	198	502
	\$ 1,393	\$ 161	\$ 1,554	\$ 695	\$ 198	\$ 893

For the three months ended March 31, 2022, other revenue of \$24 million was attributed to Canada (March 31, 2021 – \$28 million attributed to Canada).

### b. Revenue-related assets

The Corporation has recognized the following revenue-related assets in trade receivables and other:

As at	March 31, 2022		December 31, 2021	
Petroleum revenue	\$	596	\$	455
Other revenue		7		10
Total revenue-related assets	\$	603	\$	465

Revenue-related receivables are typically settled within 30 days. As at March 31, 2022 and December 31, 2021, there was no material expected credit loss required against revenue-related receivables.

## 12. FOREIGN EXCHANGE (GAIN) LOSS, NET

Three months ended March 31	2022	2021
Unrealized foreign exchange (gain) loss on:		
Long-term debt	\$ (31)	\$ (48)
US\$ denominated cash and cash equivalents	9	5
Foreign currency risk management contracts	(7)	—
Unrealized net (gain) loss on foreign exchange	(29)	(43)
Realized (gain) loss on foreign exchange	1	—
Foreign exchange (gain) loss, net	\$ (28)	\$ (43)
<b>C\$ equivalent of 1 US\$</b>		
Beginning of period	1.2656	1.2755
End of period	1.2484	1.2572

## 13. NET FINANCE EXPENSE

Three months ended March 31	2022	2021
Interest expense on long-term debt	\$ 47	\$ 58
Interest expense on lease liabilities	6	6
Net interest expense	53	64
Accretion on provisions	2	2
Net finance expense	\$ 55	\$ 66

## 14. INCOME TAX EXPENSE (RECOVERY)

Three months ended March 31	2022	2021
Current income tax expense (recovery)	\$ —	\$ —
Deferred income tax expense (recovery)	104	(19)
Income tax expense (recovery)	\$ 104	\$ (19)

For the three months ended March 31, 2022, an income tax expense was recognized compared to an income tax recovery in the same period of 2021 due to increased earnings before income taxes and foreign exchange gains and losses on long-term debt.

## 15. SUPPLEMENTAL CASH FLOW DISCLOSURES

Three months ended March 31	2022	2021
Cash provided by (used in):		
Trade receivables and other	\$ (184)	\$ (118)
Inventories	(69)	(34)
Accounts payable and accrued liabilities	35	107
Interest payable	(51)	(43)
	\$ (269)	\$ (88)
Changes in non-cash working capital relating to:		
Operating	\$ (270)	\$ (109)
Investing	1	21
	\$ (269)	\$ (88)
Cash and cash equivalents: <sup>(a)</sup>		
Cash	\$ 290	\$ 54
Cash equivalents	—	—
	\$ 290	\$ 54
Cash interest paid	\$ 94	\$ 96

- a. As at March 31, 2022, \$270 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (March 31, 2021 – \$31 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US\$1 = C\$1.2484 (March 31, 2021 – US\$1=C\$1.2572).

The following table provides a reconciliation of assets and liabilities to cash flows arising from financing activities:

	Finance sublease receivables	Lease liabilities	Long-term debt
Balance as at December 31, 2021	\$ 15	\$ 266	\$ 2,762
Financing cash flow changes:			
Receipts on leased assets	(1)	—	—
Payments on leased liabilities	—	(6)	—
Repayment and redemption of long-term debt	—	—	(288)
Debt redemption premium and refinancing costs	—	—	(5)
Other cash and non-cash changes:			
Interest payments on lease liabilities	—	(6)	—
Interest expense on lease liabilities	—	6	—
Unrealized (gain) loss on foreign exchange	—	—	(31)
Amortization of deferred debt discount and debt issue costs	—	—	2
<b>Balance as at March 31, 2022</b>	<b>\$ 14</b>	<b>\$ 260</b>	<b>\$ 2,440</b>

(i) Finance sublease receivables, Lease liabilities & Long-term debt all include their respective current portion.

## 16. NET EARNINGS (LOSS) PER COMMON SHARE

Three months ended March 31	2022		2021	
Net earnings (loss)	\$	362	\$	(17)
Weighted average common shares outstanding (millions) <sup>(a)</sup>		307		303
Dilutive effect of stock options, RSUs and PSUs (millions) <sup>(b)</sup>		7		—
Weighted average common shares outstanding – diluted (millions)		314		303
Net earnings (loss) per share, basic	\$	1.18	\$	(0.06)
Net earnings (loss) per share, diluted	\$	1.15	\$	(0.06)

- a. Weighted average common shares outstanding for the three months ended March 31, 2022 include nil PSUs vested but not yet released (three months ended March 31, 2021 - 493,829 PSUs).
- b. For the three months ended March 31, 2021, the Corporation incurred a net loss and therefore there was no dilutive effect of stock options, RSUs and PSUs. If the Corporation had recognized net earnings for the three months ended March 31, 2021, the dilutive effect of stock options, RSUs and PSUs would have been 6.1 million weighted average common shares.

## 17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments recognized on the consolidated balance sheet are comprised of cash and cash equivalents, trade receivables and other, risk management contracts, accounts payable and accrued liabilities, interest payable and long-term debt.

- a. Fair values:

The carrying values of cash and cash equivalents, trade receivables and other, accounts payable and accrued liabilities and interest payable included on the consolidated balance sheet approximates the fair values of the respective assets and liabilities due to the short-term nature of those instruments.

The following fair values are based on Level 2 inputs to fair value measurement:

As at	March 31, 2022		December 31, 2021	
	Carrying amount	Fair value	Carrying amount	Fair value
Recurring measurements:				
Financial assets				
Commodity risk management contracts	\$ 7	\$ 7	\$ 3	\$ 3
Equity price risk management contracts	\$ 71	\$ 71	\$ 74	\$ 74
Financial liabilities				
Long-term debt (Note 7)	\$ 2,461	\$ 2,543	\$ 2,779	\$ 2,888
Foreign currency risk management contracts	\$ —	\$ —	\$ 7	\$ 7

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker. The fair value was determined based on estimates as at March 31, 2022 and is expected to fluctuate given the volatility in the debt and commodity price markets.

The fair value of risk management contracts is derived using third-party valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including forward prices for commodities, interest rate yield curves and foreign exchange rates. The observable inputs may be adjusted using certain methods, which include extrapolation to the end of the term of the contract.



b. Risk management:

The Corporation's risk management assets and liabilities consist of natural gas swaps, condensate swaps and equity swaps. The use of the financial risk management contracts is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes. Financial risk management contracts are measured at fair value, with gains and losses on re-measurement included in the consolidated statement of earnings and comprehensive income in the period in which they arise.

The Corporation's financial risk management contracts are subject to master agreements that create a legally enforceable right to offset, by counterparty, the related financial assets and financial liabilities on the Corporation's balance sheet in all circumstances.

The following table provides a summary of the Corporation's unrealized offsetting financial risk management positions:

As at	March 31, 2022			December 31, 2021		
	Asset	Liability	Net	Asset	Liability	Net
Gross amount	\$ 78	\$ —	\$ 78	\$ 77	\$ (7)	\$ 70
Amount offset	—	—	—	—	—	—
Net amount	\$ 78	\$ —	\$ 78	\$ 77	\$ (7)	\$ 70
Current portion	\$ 76	\$ —	\$ 76	\$ 36	\$ (7)	\$ 29
Non-current portion	2	—	2	41	—	41
Net amount	\$ 78	\$ —	\$ 78	\$ 77	\$ (7)	\$ 70

The following table provides a reconciliation of changes in the fair value of the Corporation's financial risk management assets and liabilities from January 1 to March 31:

As at March 31	2022	2021
Fair value of contracts, beginning of year	\$ 70	\$ (2)
Fair value of contracts realized	(47)	69
Change in fair value of contracts	55	(146)
Fair value of contracts, end of period	\$ 78	\$ (79)

c. Commodity risk management:

The Corporation had the following financial commodity risk management contracts relating to condensate and natural gas purchases outstanding as at March 31, 2022:

As at March 31, 2022			
	Volumes (bbls/d) <sup>(i)</sup>	Term	Average Price (US\$/bbl) <sup>(i)</sup>
<b>Condensate Purchase Contracts</b>			
WTI:Mont Belvieu Fixed Differential	200	Apr 1, 2022 - Dec 31, 2022	\$(11.30)
<b>Natural Gas Purchase Contracts</b>			
AECO Fixed Price	5,000	Apr 1, 2022 - Dec 31, 2023	\$2.50

(i) The volumes and prices in the above table represent averages for various contracts with differing terms and prices. The average prices for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.

The Corporation did not enter into financial commodity risk management contracts between March 31, 2022 and May 2, 2022.

The following table summarizes the financial commodity risk management gains and losses:

<b>Three months ended March 31</b>	<b>2022</b>	<b>2021</b>
Realized loss (gain) on commodity risk management	\$ (1) \$	69
Unrealized loss (gain) on commodity risk management	(4)	88
Commodity risk management (gain) loss, net	\$ (5) \$	157

d. Equity price risk management:

In 2020, the Corporation entered into financial equity price risk management contracts to increase the predictability of the Corporation's cash flow by managing share price volatility. Equity price risk is the risk that changes in the Corporation's own share price impact earnings and cash flows. Earnings and funds flow from operating activities are impacted when outstanding cash-settled RSUs and PSUs, issued under the Corporation's stock-based compensation plans, are revalued each period based on the Corporation's share price and the revaluation is recognized in stock-based compensation expense. Net cash provided by (used in) operating activities is impacted when these stock-based compensation units are ultimately settled. The Corporation entered into these equity price risk management contracts in March 2020 to manage its exposure on cash-settled RSUs and PSUs vesting between April 1, 2021 and April 1, 2023.

<b>Three months ended March 31</b>	<b>2022</b>	<b>2021</b>
Realized equity price risk management (gain) loss	\$ (46) \$	(8)
Unrealized equity price risk management (gain) loss	4	(11)
Equity price risk management (gain) loss	\$ (42) \$	(19)

e. Credit risk management:

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward looking information to determine the appropriate loss allowance provisions. Credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to each counterparty's credit quality. A substantial portion of accounts receivable are with investment grade customers in the energy industry and are subject to normal industry credit risk. The Corporation has experienced no material loss in relation to trade receivables. As at March 31, 2022, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was \$630 million. All amounts receivable from commodity risk management activities are due from large Canadian banks with strong investment grade credit ratings. Counterparty default risk associated with the Corporation's commodity risk management activities is also partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in note 23 of the Corporation's 2021 annual consolidated financial statements.

The Corporation's cash balances are used to repay debt, fund sustaining capital, return capital to shareholders or fund future production growth. The cash balances are held in high interest savings accounts or are invested in high grade, liquid, short-term instruments such as bankers' acceptances, commercial paper, money market deposits or similar instruments. The cash and cash equivalents balance at March 31, 2022 was \$290 million. None of the investments are past their maturity or considered impaired. The Corporation's estimated maximum exposure to credit risk related to its cash and cash equivalents is \$290 million.

f. Liquidity risk management:

Liquidity risk is the risk that the Corporation will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk that the Corporation cannot generate sufficient cash flow from the Christina Lake Project or is unable to raise further capital in order to meet its obligations under its debt agreements. The lenders are entitled to exercise any and all remedies available under the debt agreements. The Corporation manages its liquidity risk through the active management of cash, debt and revolving credit facilities and by maintaining appropriate access to credit.

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. Meeting current and future obligations through periods of volatility is supported by the Corporation's financial framework and credit risk management policies minimizing exposure related to customer receivables primarily to investment grade customers in the energy industry. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary.

After the April 2022 debt redemption disclosed in Note 7, the Corporation's earliest maturing long-term debt will be approximately five years out, represented by US\$1.2 billion of senior unsecured notes due February 2027. None of the Corporation's outstanding long-term debt contain financial maintenance covenants. Additionally, the Corporation's modified covenant-lite \$800 million revolving credit facility has no financial maintenance covenant unless drawn in excess of \$400 million. If drawn in excess of \$400 million, the Corporation is required to maintain a quarterly first lien net leverage ratio (first lien net debt to last twelve-month EBITDA) of 3.5 or less. Under the Corporation's credit facility, first lien net debt is calculated as debt under the credit facility plus other debt that is secured on a *pari passu* basis with the credit facility, less cash on hand.

## 18. CAPITAL MANAGEMENT

The Corporation's capital consists of cash and cash equivalents, debt and shareholders' equity. The Corporation's objective for managing capital is to prioritize balance sheet strength while maintaining flexibility to repay debt, fund sustaining capital, return capital to shareholders or fund future production growth. In the current price environment, management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. Debt repayment and sustaining capital expenditure activities are anticipated to be funded by the Corporation's adjusted funds flow, cash-on-hand and/or other available liquidity.

On January 18, 2022, the Corporation repaid US\$225 million (approximately C\$285 million) of the 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625%, plus accrued and unpaid interest to, but not including, the redemption date.

On March 3, 2022 the Corporation announced that it had issued a notice to redeem the remaining outstanding balance of US\$171 million (approximately C\$214 million) of the 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625%, plus accrued and unpaid interest to, but not including, the redemption date. The redemption was completed on April 4, 2022.

Both of these redemptions included prepayment options, recognized as at December 31, 2021. The Corporation is required to assess the likelihood of exercising prepayment options at each reporting date.

After the April 2022 debt redemption disclosed in Note 7, the Corporation's earliest maturing long-term debt will be approximately five years out, represented by US\$1.2 billion of senior unsecured notes due February 2027. As at March 31, 2022, the Corporation had \$794 million of unutilized capacity under the \$800 million revolving credit facility and had \$108 million of unutilized capacity under the \$500 million letter of credit facility. A letter of credit of \$15 million was issued under the revolving credit facility during the first quarter of 2020 and \$6 million remains outstanding as at March 31, 2022.

The following table summarizes the Corporation's net debt:

<b>As at</b>	<b>Note</b>	<b>March 31, 2022</b>	<b>December 31, 2021</b>
Long-term debt	7	\$ 2,226	\$ 2,477
Current portion of long-term debt	7	214	285
Cash and cash equivalents		(290)	(361)
Net debt - C\$		\$ 2,150	\$ 2,401
Net debt - US\$		\$ 1,722	\$ 1,897

Net debt is an important measure used by management to analyze leverage and liquidity.

The following table summarizes the Corporation's funds flow from operating activities, adjusted funds flow and free cash flow :

<b>Three months ended March 31</b>	<b>2022</b>	<b>2021</b>
Funds flow from operating activities	\$ 587	\$ 121
Adjustments:		
Payments on onerous contract	—	6
Adjusted funds flow	587	127
Capital expenditures	(88)	(70)
Free cash flow	\$ 499	\$ 57

Management utilizes funds flow from operating activities, adjusted funds flow and free cash flow as measures to analyze operating performance and cash flow generating ability. Funds flow from operating activities, adjusted funds flow and free cash flow impact the level and extent of debt repayment, funding for capital expenditures and returning capital to shareholders. By excluding non-recurring items from cash flows, the funds flow from operating activities and adjusted funds flow measures provide meaningful metrics for management by establishing a clear link between the Corporation's cash flows and the operating netbacks from the Christina Lake Project. Free cash flow provides a meaningful metric to assist management and investors in analyzing corporate performance as a measure of financial liquidity and the capacity of the business to repay debt and return capital to shareholders. Funds flow from operating activities, adjusted funds flow and free cash flow are not intended to represent net cash provided by (used in) operating activities.

Net debt, adjusted funds flow and free cash flow are not standardized measures and may not be comparable with the calculation of similar measures by other companies.

## 19. COMMITMENTS AND CONTINGENCIES

### a. Commitments

The Corporation's commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at March 31, 2022:

	2022	2023	2024	2025	2026	Thereafter	Total
Transportation and storage <sup>(i)</sup>	\$ 302	\$ 413	\$ 440	\$ 416	\$ 378	\$ 5,401	\$ 7,350
Diluent purchases	130	28	—	—	—	—	158
Other operating commitments	12	16	14	13	13	23	91
Variable office lease costs	3	5	5	5	5	22	45
Capital commitments	21	—	—	—	—	—	21
<b>Commitments</b>	<b>\$ 468</b>	<b>\$ 462</b>	<b>\$ 459</b>	<b>\$ 434</b>	<b>\$ 396</b>	<b>\$ 5,446</b>	<b>\$ 7,665</b>

(i) This represents transportation and storage commitments from 2022 to 2048, including the Access Pipeline TSA and pipeline commitments which are awaiting regulatory approval and not yet in service. Excludes finance leases recognized on the consolidated balance sheet (Note 8(a)).

b. Contingencies

The Corporation is involved in various legal claims associated with the normal course of operations. The Corporation believes that any liabilities that may arise pertaining to such matters would not have a material impact on its financial position.