SECOND QUARTER | 2022

REPORT TO SHAREHOLDERS FOR THE PERIOD ENDED JUNE 30, 2022

Report to Shareholders for the period ended June 30, 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, net transportation and storage, 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 second quarter 2022 operational and financial results on July 28, 2022.

"The second quarter saw MEG initiate its share buyback program as well as continue to make significant progress on debt reduction. Year-to-date we have applied over $1 billion of free cash flow to debt repayment and share repurchases," said Derek Evans, President and Chief Executive Officer. "Importantly in the quarter, the team safely completed on time and on budget the major planned turnaround at our Phase 2B facility in what can only be described as a challenging environment as it relates to cost and staffing pressure."

Quarterly highlights include:

- Funds flow from operating activities of $412 million ($1.31 per share) and adjusted funds flow of $478 million ($1.52 per share);
- Bitumen production volumes of 67,256 barrels per day (bbls/d) which reflects the successful completion of the major planned turnaround in the quarter as well as the previously announced unplanned electrical event which resulted in a slower than forecast production ramp-up in the month of June;
- Operating expenses net of power revenue of $12.97 per barrel, including non-energy operating costs of $5.65 per barrel. Power revenue offset energy operating costs by 30%, resulting in energy operating costs net of power revenue of $7.32 per barrel;
- Total capital expenditures of $104 million directed primarily towards sustaining and maintenance activities including approximately 44% of which was directed toward the completion of the major planned turnaround undertaken in the quarter, resulting in free cash flow of $374 million;
- Year-to-date debt reduction of US$700 million (approximately $896 million), including US$379 million (approximately $484 million) repaid in the second quarter of 2022;
- MEG initiated its share buyback program in the quarter and to date has returned $139 million of capital to shareholders through the repurchase for cancellation of approximately 7.24 million MEG common shares;
- During the quarter, MEG renewed its existing modified covenant-lite credit facilities resulting in total available credit of $1.2 billion with a maturity date of October 31, 2026; and
- On June 16, 2022 MEG announced the hiring of Mr. Ryan Kubik as the Corporation's next Chief Financial Officer who will succeed, effective August 1, 2022, Mr. Eric Toews who had previously announced his pending retirement in the first quarter of 2022.

Blend Sales Pricing

MEG realized an average AWB blend sales price of US$100.42 per barrel during the second quarter of 2022 compared to US$83.55 per barrel during the first quarter of 2022. The increase in average AWB blend sales price quarter over quarter was primarily a result of the average WTI price increasing by US$14.12 per barrel. MEG sold 79% of its sales volumes at the U.S. Gulf Coast (“USGC”) in the second quarter of 2022 compared to 58% during the first quarter of 2022.

The increase quarter over quarter is primarily the result of apportionment on the Enbridge mainline being 0% in the second quarter of 2022 compared to 10% in the first quarter of 2022.

Net transportation and storage averaged US$10.53 per barrel of AWB blend sales in the second quarter of 2022 compared to US$7.01 per barrel of AWB blend sales in the first quarter of 2022. The increase was primarily a result of more barrels being sold in the USGC in the quarter compared to the first quarter of 2022. Also contributing to the increase was fixed transportation costs being spread over lower bitumen sales volumes, primarily as a result of the major planned turnaround.

Operational Performance

Bitumen production averaged 67,256 bbls/d at a steam-oil ratio ("SOR") of 2.46 in the second quarter of 2022, compared to 101,128 bbls/d at a SOR of 2.43 in the first quarter of 2022. Production in the second quarter of 2022 was impacted by the scheduled major planned turnaround at the Christina Lake Phase 2B facility which began in late April 2022 and was completed in early June 2022. Despite a tight labour market and supply chain challenges, the turnaround was safely completed on time and on budget. Also contributing to the production decrease, as previously disclosed by MEG on June 29, 2022, was an unplanned electrical event that occurred at the Christina Lake facility following the turnaround which resulted in a slower than forecast production ramp-up during the month of June. The Christina Lake facility has now returned to full production as at June 30, 2022 and MEG’s second half 2022 average production levels are expected to meet or exceed the record production levels the Corporation reached in the first quarter of 2022.

Non-energy operating costs averaged $5.65 per barrel of bitumen sales in the second quarter of 2022 compared to $4.74 per barrel in the first quarter of 2022. Energy operating costs, net of power revenue, averaged $7.32 per barrel in the second quarter of 2022 compared to $4.24 per barrel in the first quarter of 2022. This increase quarter over quarter resulted primarily from stronger natural gas prices and lower bitumen sales volumes. Power revenue offset energy operating costs by 30% during the second quarter of 2022 compared to 38% in the first quarter of 2022.

General & administrative expense (“G&A”) was relatively consistent quarter over quarter with $15 million, or $2.37 per barrel of production, in the second quarter of 2022 compared to $14 million, or $1.61 per barrel of production, in the first quarter of 2022.

Funds Flow from Operating Activities, Adjusted Funds Flow and Net Earnings

The Corporation’s cash operating netback averaged $81.75 per barrel in the second quarter of 2022 compared to $70.21 per barrel in the first quarter of 2022. This increase in cash operating netback was primarily driven by the increase in average bitumen realization due to the higher WTI price in the second quarter of 2022. The Corporation’s funds flow from operating activities and adjusted funds flow was $412 million and $478 million, respectively, in the second quarter of 2022 compared to $587 million and $559 million in the first quarter of 2022.

The Corporation recognized net earnings of $225 million in the second quarter of 2022 compared to $362 million in the first quarter of 2022. The decrease in funds flow from operating activities, adjusted funds flow and net earnings was primarily due to lower blend sales volumes.

Capital Expenditures

Capital expenditures in the second quarter of 2022 totaled $104 million compared to $88 million in the first quarter of 2022. Capital invested in the quarter was directed towards sustaining and maintenance activities as well as the major planned turnaround.

Capital Allocation Strategy

MEG's capital allocation strategy is designed to provide increasing return of capital to shareholders as progressively lower net debt targets are reached.

At net debt levels above US$1.7 billion 100% of free cash flow was directed to debt reduction. At net debt levels between US$1.7 billion and US$1.2 billion approximately 25% of free cash flow generated is being allocated to share buybacks with the remaining free cash flow applied to ongoing debt reduction. At net debt levels below US$1.2 billion but above MEG's net debt floor of US$600 million approximately 50% of free cash flow generated will be allocated to share buybacks with the remainder applied to further debt reduction. Once the net debt floor of US$600 million is reached 100% of free cash flow will be returned to shareholders.

MEG reached its US$1.7 billion net debt target in the second quarter of 2022. In the current commodity price environment MEG expects to reach its US$1.2 billion net debt target in October 2022 and to reach its US$600 million net debt floor in the second half of 2023.

Debt Repayment

During the second quarter of 2022, MEG repaid US$379 million (approximately $484 million) through the redemption of the remaining US$171 million (approximately $216 million) of MEG's outstanding 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625% and through the repurchase and extinguishment of US$208 million (approximately $268 million) of MEG's outstanding 7.125% senior unsecured notes due February 2027 at a weighted average price of 103.2%. Subsequent to the quarter, MEG repurchased a further US$96 million (approximately $124 million) of MEG's outstanding 7.125% senior unsecured notes due February 2027 at a weighted average price of 101%.

Year-to-date, MEG has repaid US$700 million (approximately $896 million) of outstanding indebtedness, which represents approximately one third of the US$2.3 billion of total outstanding indebtedness repaid since 2018. MEG remains committed to continued debt reduction as a key component of its capital allocation strategy.

Share Repurchases

On March 7, 2022, MEG received approval from the TSX for a NCIB which allows 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.

The Corporation began repurchasing MEG common shares for cancellation during the second quarter of 2022. During the second quarter, MEG purchased for cancellation 4.45 million common shares, returning $94 million to MEG shareholders.

Year-to-date, MEG has purchased for cancellation 7.24 million common shares, returning $139 million to MEG shareholders.

Renewal of Credit Facilities

During the second quarter of 2022 MEG amended and restated its revolving credit facility (the "Revolving Credit Facility") and its letters of credit facility guaranteed by Export Development Canada (the "EDC Facility") and extended the maturity date of each facility by 2.3 years to October 31, 2026. Total credit available under the two facilities was reduced from $1.3 billion to $1.2 billion and is comprised of $600 million under the Revolving Credit Facility and $600 million under the EDC Facility.

The Revolving Credit Facility retains its modified covenant-lite structure, meaning it continues to contain no financial maintenance covenant unless MEG is drawn under the Revolving Credit Facility in excess of 50%. If drawn in excess of 50%, or $300 million, under the Revolving Credit Facility MEG is required to maintain a 1st Lien Net Debt to LTM EBITDA ratio of 3.50 or less. The financial covenant, if triggered, is tested quarterly. MEG continues to have no 1st Lien Debt outstanding.

Sustainability

On June 15, 2022 Canada's major oil sands producers announced the combination of three existing industry groups, all focused on responsible development, into a single organization called the Pathways Alliance. The new organization incorporates the Oil Sands Pathways to Net Zero Alliance, launched in 2021, Canada's Oil Sands Innovation Alliance ("COSIA"), created in 2012, and the Oil Sands Community Alliance ("OSCA"), created in 2013.

The combination of these industry groups integrated into a single organization, with combined leadership, will enhance the Alliance's collaborative efforts to advance responsible oil sands development and to progress the Alliance's goals for responsible development, including achieving net zero greenhouse gas emissions (GHGs) from oil sands production.

A key focus of the new Pathways Alliance will be to continue the considerable work already underway to reduce GHGs from oil sands production by 22 million tonnes annually by 2030, and ultimately achieve its goal of net zero emissions from oil sands production by 2050.

Outlook

As previously disclosed June 29, 2022, during the second quarter of 2022 the Corporation took its Christina Lake Phase 2B facility down for a scheduled major turnaround. Notwithstanding significant market pressures, the turnaround was safely completed on time and on budget, impacting full year 2022 average production by approximately 6,000 bbls/d. Following the turnaround, the Christina Lake facility experienced an unplanned electrical event which resulted in a slower than forecast production ramp-up during the month of June which impacted full year 2022 average production by approximately 2,000 bbls/d. The Christina Lake facility has now returned to full production and MEG's second half 2022 average production levels are expected to meet or exceed the record production levels the Corporation reached in the first quarter of 2022. Due to the slower June production ramp-up MEG revised its full year 2022 average production guidance to 92,000 to 95,000 bbls/d from 94,000 to 97,000 bbls/d. MEG also revised its full year non-energy operating costs and G&A expense to $4.60 to $4.90 per barrel and $1.75 to $1.90 per barrel, respectively, reflecting lower full year 2022 production guidance.

MEG continues to expect full year 2022 total transportation costs to average between US$7.50 to US$8.00 per barrel of AWB blend sales.

Summary of 2022 Guidance	Revised Guidance (June 29, 2022)	Original Guidance (November 29, 2021)
Bitumen production - annual average	92,000 - 95,000 bbls/d	94,000 - 97,000 bbls/d
Non-energy operating costs	$4.60 - $4.90 per bbl	$4.50 - $4.80 per bbl
G&A expense	$1.75 - $1.90 per bbl	$1.70 - $1.85 per bbl
Capital expenditures	$375 million	$375 million

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 second 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 and six months ended June 30, 2022 was approved by the Corporation's Audit Committee on July 28, 2022. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three and six months ended June 30, 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*
    - *Net transportation and storage*
    - *Operating expenses net of power revenue*
    - *Effective royalty rate*
    - *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 concentrated on leases within 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 and is also available on the SEDAR website at www.sedar.com.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The Corporation generated funds flow from operating activities of $412 million and adjusted funds flow of $478 million in the second quarter of 2022 compared to $160 million and $184 million, respectively, in the second quarter of 2021. The increased funds flow from operating activities and adjusted funds flow were primarily driven by significant strengthening of global crude oil prices over the first half of 2022. The Corporation's realized blend sales price averaged $128.20 per barrel in the second quarter of 2022 compared to $69.27 per barrel in the second quarter of 2021 resulting primarily from a US$42.34 per barrel increase in the WTI benchmark price.

Production volumes averaged 67,256 barrels per day in the second quarter of 2022 compared to 91,803 barrels per day during the second quarter of 2021. The decrease was primarily due to the major planned turnaround at the Christina Lake Phase 2B facility which began in late April 2022 and was completed on time and on budget in early June 2022. Also contributing to the production decrease was an unplanned electrical event at the Christina Lake facility following the turnaround, which resulted in a slower than forecast production ramp-up during the month of June and impacted full year average production by approximately 2,000 barrels per day. The Christina Lake facility returned to full production as at June 30, 2022.

Capital expenditures were $104 million in the second quarter of 2022 compared to $71 million during the second quarter of 2021. Approximately 44%, or $46 million, of the capital expenditures during the second quarter of 2022 were directed towards the major planned turnaround. The Corporation continues to maintain annual 2022 capital expenditures guidance of $375 million.

Free cash flow in the second quarter of 2022 increased to $374 million compared to $113 million in the second quarter of 2021.

The Corporation recognized net earnings of $225 million in the second quarter of 2022 compared to $68 million in the second quarter of 2021. Increased earnings were mainly due to stronger global crude oil prices partially offset by lower blend sales volumes and an unrealized foreign exchange loss on U.S. dollar denominated debt during the second quarter of 2022. Net earnings recognized in the second quarter of 2021 were impacted by losses on commodity risk management, whereas the Corporation has not entered into significant commodity risk management contracts for 2022.

During the second quarter of 2022, the Corporation repaid a total of US$379 million (approximately $484 million) of outstanding indebtedness. This reduction in outstanding indebtedness was achieved through the redemption of the remaining US$171 million (approximately $216 million) of MEG's outstanding 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625% and through the repurchase of US$208 million (approximately $268 million) of MEG's outstanding 7.125% senior unsecured notes due February 2027 at a weighted average price of 103.2%.

Subsequent to the second quarter of 2022, the Corporation repurchased a further US$96 million (approximately $124 million) of the Corporation's outstanding 7.125% senior unsecured notes due February 2027 at a weighted average price of 101%.

To date in 2022, the Corporation has repaid US$700 million (approximately $896 million) of outstanding indebtedness, which represents one third of the US$2.3 billion of total outstanding indebtedness repaid since 2018 and the Corporation remains committed to continued debt reduction as a key component of its capital allocation strategy.

During the second quarter of 2022, the Corporation reached its initial net debt target of US$1.7 billion and began repurchasing MEG common shares for cancellation. As at June 30, 2022, the Corporation had purchased for cancellation 4.45 million common shares, returning $94 million to MEG shareholders. To date in 2022, the Corporation has purchased for cancellation 7.24 million common shares, returning $139 million to MEG shareholders.

On June 24, 2022, the Corporation amended and restated its revolving credit facility (the "Revolving Credit Facility") and its letters of credit facility guaranteed by Export Development Canada (the "EDC Facility") and extended the maturity date of each facility by 2.3 years to October 31, 2026. Total credit available under the two facilities was reduced from $1.3 billion to $1.2 billion and is comprised of $600 million under the Revolving Credit Facility and $600 million under the EDC Facility.

The Revolving Credit Facility retains its modified covenant-lite structure, meaning it continues to contain no financial maintenance covenant unless the Corporation is drawn under the Revolving Credit Facility in excess of 50%. If drawn in excess of 50%, or $300 million, under the Revolving Credit Facility the Corporation is required to maintain a first lien net debt to last twelve month EBITDA ratio of 3.50 or less. The Corporation continues to have no first lien debt outstanding.

As at June 30, 2022, cash and cash equivalents were $244 million. The Corporation exited the quarter with long-term debt of $2.0 billion and net debt of approximately $1.8 billion (approximately US$1.4 billion).

On June 16, 2022, the Corporation announced the appointment of Ryan Kubik as the Corporation's new Chief Financial Officer effective August 1, 2022. Mr. Kubik will succeed Mr. Eric Toews who, as previously announced, will retire effective September 1, 2022.

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:

	Six months ended June 30		2022		2021				2020	
($millions, except as indicated)	**2022**	**2021**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
Bitumen production - bbls/d	**84,099**	91,326	**67,256**	101,128	100,698	91,506	91,803	90,842	91,030	71,516
Steam-oil ratio	**2.44**	2.38	**2.46**	2.43	2.42	2.56	2.39	2.37	2.31	2.36
Bitumen sales - bbls/d	**86,564**	88,646	**73,091**	100,186	98,894	92,251	89,980	87,298	95,731	67,569
Bitumen realization[1] - $/bbl	**108.07**	56.30	**122.69**	97.28	71.06	64.91	60.09	52.34	38.64	39.68
Operating expenses net of power revenue[1] - $/bbl	**10.68**	5.39	**12.97**	8.98	8.20	7.17	5.54	5.25	6.98	6.05
Operating expenses - $/bbl	**13.46**	8.24	**16.05**	11.54	10.78	9.23	8.11	8.39	8.43	7.13
Non-energy operating costs[2] - $/bbl	**5.13**	3.94	**5.65**	4.74	4.56	4.46	3.84	4.05	4.70	3.96
Cash operating netback[1] - $/bbl	**75.10**	28.73	**81.75**	70.21	37.87	37.31	31.30	26.03	18.66	16.58
General & administrative expense - $/bbl of bitumen production volumes	**1.92**	1.66	**2.37**	1.61	1.58	1.72	1.56	1.77	1.65	1.50
Funds flow from operating activities	**999**	281	**412**	587	260	212	160	121	81	19
Per share, diluted	**3.18**	0.91	**1.31**	1.87	0.83	0.68	0.51	0.39	0.26	0.06
Adjusted funds flow[3]	**1,038**	308	**478**	559	274	243	184	124	88	26
Per share, diluted[3]	**3.30**	0.99	**1.52**	1.78	0.88	0.78	0.59	0.40	0.29	0.09
Revenues	**3,102**	1,923	**1,571**	1,531	1,307	1,091	1,009	914	786	533
Net earnings (loss)	**587**	51	**225**	362	177	54	68	(17)	16	(9)
Per share, diluted	**1.87**	0.17	**0.72**	1.15	0.57	0.17	0.22	(0.06)	0.05	(0.03)
Capital expenditures	**192**	141	**104**	88	106	84	71	70	40	35
Long-term debt, including current portion	**2,026**	2,820	**2,026**	2,440	2,762	2,769	2,820	2,852	2,912	3,030
Net debt[3] - C$	**1,782**	2,661	**1,782**	2,150	2,401	2,559	2,661	2,798	2,798	2,981
Net debt[3] - US$	**1,384**	2,145	**1,384**	1,722	1,897	2,007	2,145	2,226	2,194	2,237

(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 June 15, 2022 Canada's major oil sands producers announced the combination of three existing industry groups, all focused on responsible development, into a single organization called the Pathways Alliance. The new organization incorporates the Oil Sands Pathways to Net Zero Alliance, launched in 2021, Canada's Oil Sands Innovation Alliance ("COSIA"), created in 2012, and the Oil Sands Community Alliance ("OSCA"), created in 2013.

The combination of these industry groups integrated into a single organization, with combined leadership, will enhance the Alliance's collaborative efforts to advance responsible oil sands development and to progress the Alliance's goals for responsible development, including achieving net zero greenhouse gas emissions (GHGs) from oil sands production.

A key focus of the new Pathways Alliance will be to continue the considerable work already underway to reduce GHGs from oil sands production by 22 million tonnes annually by 2030, and ultimately achieve its goal of net zero emissions from oil sands production 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 and the most recently filed AIF on www.sedar.com.

4. NET EARNINGS

	Three months ended June 30		Six months ended June 30	
($millions, except per share amounts)	**2022**	**2021**	**2022**	**2021**
Net earnings	**$ 225**	$ 68	**$ 587**	$ 51
Per share, diluted	**$ 0.72**	$ 0.22	**$ 1.87**	$ 0.17

The Corporation recognized net earnings of $225 million and $587 million for the three and six months ended June 30, 2022, respectively, compared to $68 million and $51 million during the same periods of 2021. Increased net earnings during the three and six months ended June 30, 2022 was primarily due to stronger global crude oil prices and a reduction in commodity risk management losses, partially offset by lower blend sales volumes and an unrealized foreign exchange loss as the Canadian dollar weakened relative to the U.S. dollar during the first half of 2022.

5. REVENUES

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

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Sales from:				
Production	**$ 1,224**	$ 813	**$ 2,617**	$ 1,508
Purchased product[1]	**383**	187	**544**	385
Petroleum revenue	**$ 1,607**	$ 1,000	**$ 3,161**	$ 1,893
Royalties	**(58)**	(14)	**(105)**	(21)
Petroleum revenue, net of royalties	**$ 1,549**	$ 986	**$ 3,056**	$ 1,872
Power revenue	**$ 21**	$ 21	**$ 44**	$ 46
Transportation revenue	**1**	2	**2**	5
Other revenue	**$ 22**	$ 23	**$ 46**	$ 51
Revenues	**$ 1,571**	$ 1,009	**$ 3,102**	$ 1,923

(1) 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 and six months ended June 30, 2022, revenues increased from the same periods 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. This was partially offset by a decrease in blend sales volumes and increased royalties as a result of higher benchmark WTI pricing.

6. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended June 30		Six months ended June 30	
	2022	**2021**	**2022**	**2021**
Bitumen production – bbls/d	**67,256**	91,803	**84,099**	91,326
Steam-oil ratio (SOR)	**2.46**	2.39	**2.44**	2.38

Bitumen Production

Bitumen production decreased 27% and 8% during the three and six months ended June 30, 2022 compared to the same periods of 2021, respectively. The decrease was primarily due to the major planned turnaround at the Christina Lake Phase 2B facility, which began in late April 2022 and was completed in early June 2022, as well as an unplanned electrical event at the Christina Lake facility following the turnaround which resulted in a slower than forecast production ramp-up during the month of June. By June 30, 2022, the Christina Lake facility had returned to full production. The reduction in bitumen production during the first half of 2022 was partially offset by strong field-wide production performance during the first quarter of 2022.

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 and six months ended June 30, 2022, compared to the same periods of 2021, due to the timing of new well pairs converted to SAGD and work performed on infill wells.

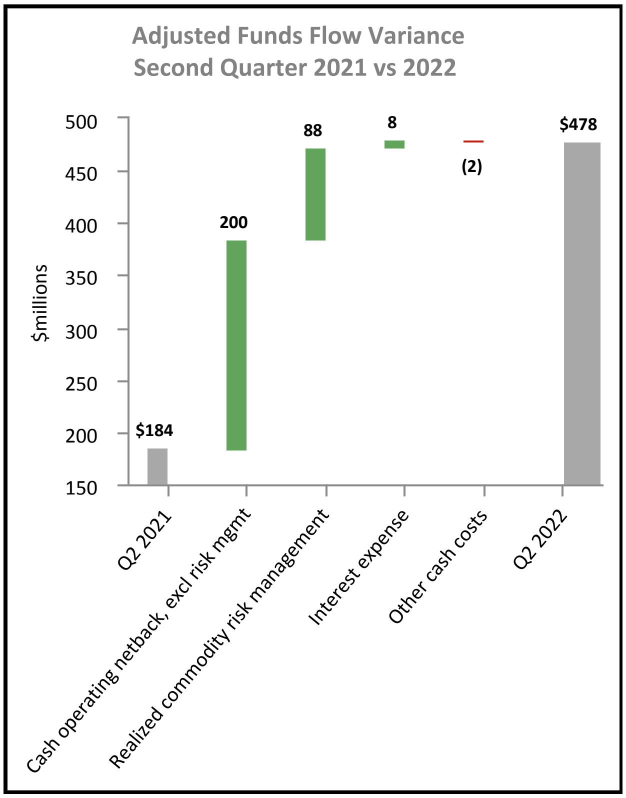
Funds Flow from Operating Activities and Adjusted Funds Flow

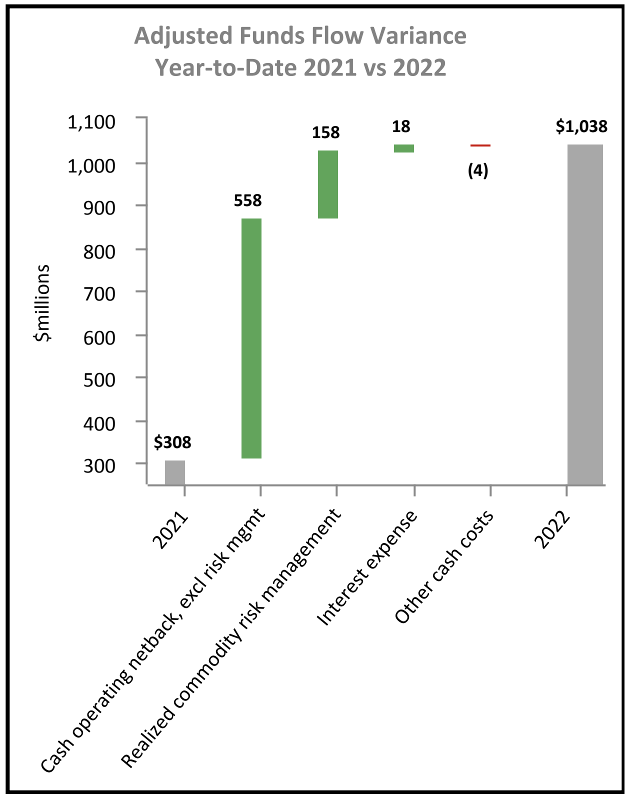
Funds flow from operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as funds flow from operating activities excluding items not considered part of ordinary continuing operating results. Adjusted funds flow is used by management 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.

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

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Funds flow from operating activities	**$ 412**	$ 160	**$ 999**	$ 281
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management[(1)]	**66**	18	**85**	23
Realized equity price risk management gain[(1)]	**—**	—	**(46)**	(8)
Payments on onerous contract	**—**	6	**—**	12
Adjusted funds flow	**$ 478**	$ 184	**$ 1,038**	$ 308
Per share, diluted	**$ 1.52**	$ 0.59	**$ 3.30**	$ 0.99

(1) As of June 30, 2022, the impact of these items has been removed from the capital management measure of Adjusted Funds Flow. All prior period measures have been adjusted to conform to the current period presentation. Please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.





During the three and six months ended June 30, 2022, funds flow from operating activities and adjusted funds flow increased compared to the same periods of 2021, driven mainly by a higher cash operating netback reflecting stronger global crude oil prices partially offset by decreased blend sales volumes associated with the major planned turnaround during the quarter. Additionally, commodity risk management losses in 2021 also reduced adjusted funds flow relative to the second quarter and year-to-date 2022.

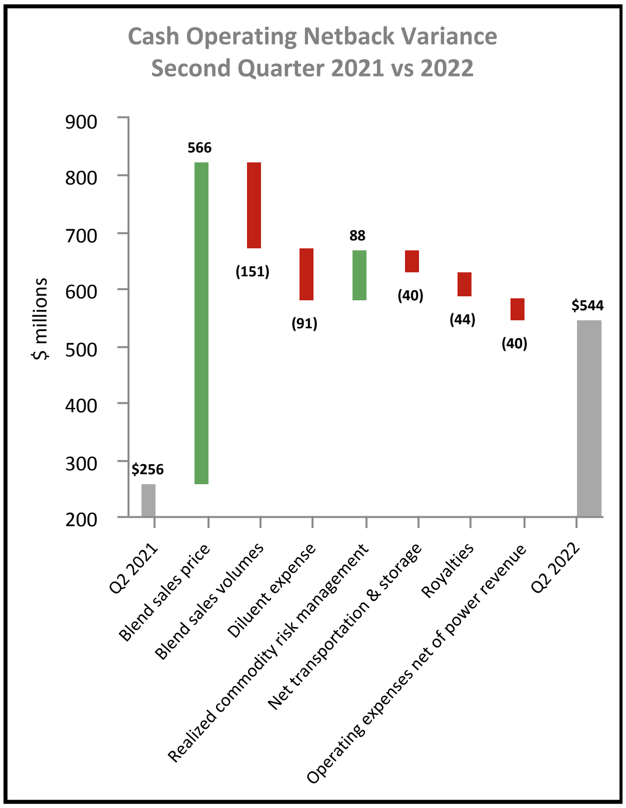
Cash Operating Netback

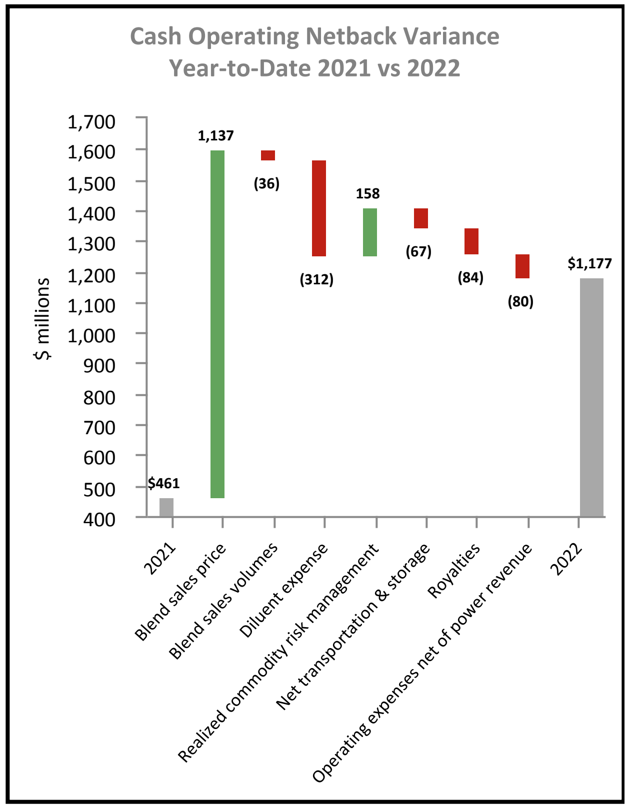
The following table summarizes the Corporation's cash operating netback. Unless otherwise indicated, the per barrel calculation for the periods indicated below are based on bitumen sales volume.

	Three months ended June 30				Six months ended June 30			
	2022		2021		2022		2021	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Sales from production	**$ 1,224**		$ 813		**$ 2,617**		$ 1,508	
Sales from purchased product[1]	**383**		187		**544**		385	
Petroleum revenue	**1,607**		1,000		**3,161**		1,893	
Purchased product[1]	**(376)**		(184)		**(536)**		(369)	
Blend sales[2][3]	**$ 1,231**	**$128.20**	$ 816	$ 69.27	**$ 2,625**	**$115.23**	$ 1,524	$ 65.32
Diluent expense	**(415)**	**(5.51)**	(324)	(9.18)	**(932)**	**(7.16)**	(620)	(9.02)
Bitumen realization[3]	**816**	**122.69**	492	60.09	**1,693**	**108.07**	904	56.30
Net transportation and storage[3][4]	**(129)**	**(19.40)**	(89)	(10.91)	**(246)**	**(15.70)**	(179)	(11.15)
Royalties	**(58)**	**(8.67)**	(14)	(1.71)	**(105)**	**(6.70)**	(21)	(1.29)
Operating expenses net of power revenue[3]	**(86)**	**(12.97)**	(46)	(5.54)	**(167)**	**(10.68)**	(87)	(5.39)
Realized gain (loss) on commodity risk management	**1**	**0.10**	(87)	(10.63)	**2**	**0.11**	(156)	(9.74)
Cash operating netback[3]	**$ 544**	**$ 81.75**	$ 256	$ 31.30	**$ 1,177**	**$ 75.10**	$ 461	$ 28.73
Bitumen sales volumes - bbls/d		**73,091**		89,980		**86,564**		88,646

(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) Net transportation and storage includes costs associated with moving and storing AWB 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 marketing 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 diluent expense, 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. Diluent expense 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 June 30				**Six months ended June 30**			
	2022		**2021**		**2022**		**2021**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Sales from production	**$ 1,224**		$ 813		**$ 2,617**		$ 1,508	
Sales from purchased product(1)	**383**		187		**544**		385	
Petroleum revenue	**$ 1,607**		$ 1,000		**$ 3,161**		$ 1,893	
Purchased product(1)	**(376)**		(184)		**(536)**		(369)	
Blend sales(2)(3)	**$ 1,231**	**$128.20**	$ 816	$ 69.27	**$ 2,625**	**$115.23**	$ 1,524	$ 65.32
Diluent expense	**(415)**	**(5.51)**	(324)	(9.18)	**(932)**	**(7.16)**	(620)	(9.02)
Bitumen realization(3)	**$ 816**	**$122.69**	$ 492	$ 60.09	**$ 1,693**	**$108.07**	$ 904	$ 56.30

(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 increased by $58.93 per barrel and $49.91 per barrel during the three and six months ended June 30, 2022, respectively, compared to the same periods of 2021, primarily due to the increase in WTI benchmark price. The Corporation increased the proportion of its blend sales volumes sold at the USGC to 79% and 67% during the three and six months ended June 30, 2022 compared to 45% and 41% during the same periods of 2021, respectively. The increased sales volumes sold at the USGC are a result of incremental egress out of the Edmonton area following the completion of the Enbridge Line 3 Pipeline Replacement Project in late 2021. As a result, apportionment levels for heavy oil on the Enbridge mainline system averaged 0% and 5%, respectively, during the three and six months ended June 30, 2022 compared to 46% and 47% during the same periods of 2021, respectively.

Diluent expense per barrel represents the cost of diluent that is unrecovered through blend sales. The diluent expense per barrel during the three and six months ended June 30, 2022 was lower than the same periods of 2021 as more of the costs were recovered through the blend sales price as the price of diluent purchases did not increase at the same rate as the price earned on AWB blend sales.

Total diluent expense was $415 million and $932 million during the three and six months ended June 30, 2022, respectively, compared to $324 million and $620 million during the same periods of 2021, respectively. This translates to a cost per barrel of diluent during the three and six months ended June 30, 2022 of $140.61 and $131.03, respectively, compared to $90.18 and $85.20 for the same periods of 2021, respectively. 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.

Net Transportation and Storage

The Corporation's marketing strategy focuses on maximizing its 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 June 30				**Six months ended June 30**			
	2022		**2021**		**2022**		**2021**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Transportation and storage expense	**$ (130)**	**$ (19.57)**	$ (91)	$ (11.15)	**$ (248)**	**$ (15.86)**	$ (184)	$ (11.48)
Transportation revenue	**1**	**0.17**	2	0.24	**2**	**0.16**	5	0.33
Net transportation and storage	**$ (129)**	**$ (19.40)**	$ (89)	$ (10.91)	**$ (246)**	**$ (15.70)**	$ (179)	$ (11.15)
Bitumen sales volumes - bbls/d		**73,091**		89,980		**86,564**		88,646

During the three and six months ended June 30, 2022, transportation and storage expense on a total basis increased compared to the same periods of 2021. Due to low apportionment levels during the three and six months ended June 30, 2022, the Corporation was able to ship more volumes to the higher value USGC market in these periods which primarily drove the increase in transportation costs compared to the same periods of 2021.

On a per barrel basis, fixed transportation costs were spread over lower bitumen sales volumes, primarily as a result of the major planned turnaround, which contributed to the increase during the three and six months ended June 30, 2022, compared to the same periods of 2021. When expressed on a US$ per barrel of blend sales basis, net transportation and storage per barrel was US$10.53 and US$8.49 during the three and six months ended June 30, 2022, respectively, compared to US$6.17 and US$6.15 during the same periods 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 $7 million, or $0.80 per barrel, to blend sales during the three months ended June 30, 2022 compared to $3 million, or $0.25 per barrel, during the same period of 2021. Asset optimization activities added $8 million, or $0.36 per barrel, to blend sales during the six months ended June 30, 2022 compared to $16 million, or $0.66 per barrel, during the same period of 2021.

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. Gross revenues are comprised of bitumen realization less transportation and storage expense. 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. Net revenues are comprised of bitumen realization less transportation and storage expense and allowed operating and capital costs. 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. We anticipate that our Christina Lake operation will reach payout for royalty purposes in the fourth quarter of 2022 once its cumulative revenue exceeds its cumulative allowable costs. After payout is achieved, the associated royalty payable will switch to the post-payout formula as described above.

	Three months ended June 30				Six months ended June 30			
	2022		2021		2022		2021	
		$/bbl		$/bbl		$/bbl		$/bbl
Royalties ($millions)	**$ (58)**	**$ (8.67)**	$ (14)	$ (1.71)	**$ (105)**	**$ (6.70)**	$ (21)	$ (1.29)
WTI benchmark price (C$/bbl)	**$138.40**		$81.13		**$128.86**		$77.27	
Effective royalty rate(1)(2)	**8.5 %**		3.5 %		**7.3 %**		2.9 %	

(1) Effective royalty rate is calculated as royalties expense divided by bitumen realization less transportation and storage expense.

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

The C$ WTI benchmark price increased 71% and 67% during both the three and six months ended June 30, 2022, respectively, compared to the same periods of 2021. This increased the average gross royalty rate applied to 9% and 8% during the three and six months ended June 30, 2022, respectively, compared to 2% and 3% during the same periods of 2021.

Operating Expenses net of Power Revenue

Operating expenses net of power revenue are comprised 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 June 30				Six months ended June 30			
	2022		2021		2022		2021	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Non-energy operating costs[1]	**$ (38)**	**$ (5.65)**	$ (31)	$ (3.84)	**$ (80)**	**$ (5.13)**	$ (63)	$ (3.94)
Energy operating costs[1]	**(69)**	**(10.40)**	(36)	(4.27)	**(131)**	**(8.33)**	(70)	(4.30)
Operating expenses	**(107)**	**(16.05)**	(67)	(8.11)	**(211)**	**(13.46)**	(133)	(8.24)
Power revenue	**21**	**3.08**	21	2.57	**44**	**2.78**	46	2.85
Operating expenses net of power revenue[2]	**$ (86)**	**$(12.97)**	$ (46)	$ (5.54)	**$ (167)**	**$(10.68)**	$ (87)	$ (5.39)
Average delivered natural gas price (C$/mcf)		**$ 8.17**		$ 3.55		**$ 6.55**		$ 3.58
Average realized power sales price (C$/Mwh)		**$117.94**		$ 88.40		**$102.25**		$ 90.96

(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 increased for the three and six months ended June 30, 2022, compared to the same periods of 2021. The increase during the three months ended June 30, 2022 was primarily due to planned increases in maintenance activity. The increase during the six months ended June 30, 2022 was primarily due to increases in maintenance activity and chemical treating costs.

On a per barrel basis, fixed costs were spread over lower bitumen sales volumes which contributed to the increase during the three and six months ended June 30, 2022, compared to the same periods of 2021.

Total energy operating costs and energy operating costs per barrel increased during the three and six months ended June 30, 2022, compared to the same periods of 2021, primarily due to the AECO natural gas price strengthening by more than double during those respective periods, as well as lower bitumen sales volumes.

Power revenues remained consistent during the three and six months ended June 30, 2022, compared to the same periods of 2021. The Alberta power market strengthened by 17% and 5% during the three and six months ended June 30, 2022, compared to the same periods of 2021 which was offset by lower power sales volumes.

Realized Gain or Loss on Commodity 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. Financial commodity risk management contracts are also used to eliminate price risk on marketing asset optimization activities pursuant to Board approved policies.

Realized gains on commodity risk management contracts were recognized during the three and six months ended June 30, 2022 associated with fixed natural gas purchase contracts and marketing asset optimization contracts in place. The realized loss recognized in 2021 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 June 30				Six months ended June 30			
	2022		2021		2022		2021	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Realized gain (loss) on commodity risk management	**$ 1**	**$ 0.10**	$ (87)	$ (10.63)	**$ 2**	**$ 0.11**	$ (156)	$ (9.74)

Capital Expenditures

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Sustaining and maintenance	**$ 57**	$ 59	**$ 137**	$ 124
Turnaround	**46**	—	**46**	—
Phase 2B brownfield expansion	**—**	7	**—**	11
Field infrastructure, corporate and other	**1**	5	**9**	6
	$ 104	$ 71	**$ 192**	$ 141

The majority of the $104 million and $192 million invested during the three and six months ended June 30, 2022 was directed towards sustaining and maintenance activities as well as a major planned turnaround at the Phase 2B facility which began in late April 2022 and was completed in early June 2022.

7. OUTLOOK

Summary of 2022 Guidance	**Revised Guidance (June 29, 2022)[1]**	**Original Guidance (November 29, 2021)[1]**
Bitumen production - annual average	92,000 - 95,000 bbls/d	94,000 - 97,000 bbls/d
Non-energy operating costs	$4.60 - $4.90 per bbl	$4.50 - $4.80 per bbl
G&A expense	$1.75 - $1.90 per bbl	$1.70 - $1.85 per bbl
Capital expenditures	$375 million	$375 million

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

As previously disclosed June 29, 2022, during the second quarter of 2022 the Corporation took its Christina Lake Phase 2B facility down for a scheduled major turnaround. Notwithstanding significant market pressures, the turnaround was safely completed on time and on budget, impacting full year 2022 average production by approximately 6,000 bbls/d. Following the turnaround, the Christina Lake facility experienced an unplanned electrical event which resulted in a slower than forecast production ramp-up during the month of June which impacted full year 2022 average production by approximately 2,000 bbls/d. Due to the slower June production ramp-up MEG revised its full year 2022 average production guidance to 92,000 to 95,000 bbls/d from 94,000 to 97,000 bbls/d. MEG also revised its full year non-energy operating costs and G&A expense to $4.60 to $4.90 per barrel and $1.75 to $1.90 per barrel, respectively, reflecting lower full year 2022 production guidance.

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.

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	Six months ended June 30		2022		2021				2020	
	2022	2021	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Crude oil prices										
Brent (US$/bbl)	**104.40**	65.02	**111.57**	97.23	79.78	73.15	68.98	61.06	45.25	43.39
WTI (US$/bbl)	**101.35**	61.96	**108.41**	94.29	77.19	70.56	66.07	57.84	42.66	40.93
Differential – WTI:WCS – Edmonton (US$/bbl)	**(13.67)**	(11.98)	**(12.80)**	(14.53)	(14.64)	(13.58)	(11.49)	(12.47)	(9.30)	(9.09)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(15.31)**	(13.67)	**(14.25)**	(16.35)	(16.40)	(15.13)	(13.11)	(14.22)	(10.56)	(10.48)
AWB – Edmonton (US$/bbl)	**86.04**	48.29	**94.16**	77.94	60.79	55.43	52.96	43.62	32.10	30.45
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(6.00)**	(3.22)	**(6.15)**	(5.85)	(6.40)	(5.57)	(3.92)	(2.52)	(2.83)	(3.20)
AWB – U.S. Gulf Coast (US$/bbl)	**95.35**	58.74	**102.26**	88.44	70.79	64.99	62.15	55.32	39.83	37.73
Enbridge Mainline heavy crude apportionment %	**5**	47	**0**	10	21	53	46	48	22	9
Condensate prices										
Condensate at Edmonton (C$/bbl)	**130.06**	77.53	**138.39**	121.74	99.70	87.30	81.55	73.51	55.39	50.03
Condensate at Edmonton as % of WTI	**100.9**	100.3	**100.0**	102.0	102.5	98.2	100.5	100.4	99.6	91.8
Condensate at Mont Belvieu, Texas (US$/bbl)	**91.83**	58.59	**90.98**	92.68	76.62	68.19	61.18	56.00	38.52	33.52
Condensate at Mont Belvieu, Texas as a % of WTI	**90.6**	94.6	**83.9**	98.3	99.3	96.6	92.6	96.8	90.3	81.9
Natural gas prices										
AECO (C$/mcf)	**6.53**	3.40	**7.89**	5.16	5.07	3.92	3.37	3.43	2.88	2.48
Electric power prices										
Alberta power pool (C$/MWh)	**106.48**	100.99	**122.49**	90.47	107.25	100.27	104.73	97.25	46.05	43.75
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.2714**	1.2471	**1.2766**	1.2661	1.2600	1.2602	1.2280	1.2663	1.3031	1.3316
C$ equivalent of 1 US$ – period end	**1.2872**	1.2405	**1.2872**	1.2484	1.2656	1.2750	1.2405	1.2572	1.2755	1.3324

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 half 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 first half 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.

Enbridge Mainline Heavy Crude Apportionment

During the three and six months ended June 30, 2022 Enbridge mainline heavy crude apportionment was 0% and 5%, respectively, compared to 46% and 47% during the same periods of 2021. This significant year over year decrease in apportionment is largely attributable to the Enbridge Line 3 Replacement project which was placed into full service in October 2021 and restored 370,000 barrels per day of egress capacity for Western Canadian crude. With decreased apportionment, the Corporation was able to more fully utilize its committed FSP capacity and deliver increased AWB volumes to the USGC, enabling a higher percentage of sales in the USGC market.

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. Condensate at Edmonton as a percentage of WTI during the first half of 2022 was in line with the same periods of 2021. Condensate at Mont Belvieu, Texas as a percentage of WTI weakened during the first half of 2022 compared to the same periods of 2021.

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 twelve months after lower availability of renewable wind power in the summer of 2021, the closure of nuclear plants in Germany and lower Russian exports that led to increased reliance on North American natural gas and resulted in record low storage levels. Also, a surge in U.S. exports and very tight balances in North America have contributed to the increase in natural gas pricing. As a result, the AECO natural gas price increased approximately 134% and 92% during the three and six months ended June 30, 2022 compared to the same periods of 2021.

Electric Power Prices

Electric power prices impact the revenue that the Corporation receives on the sale of surplus power from the Corporation's cogeneration facilities. The Alberta power pool price strengthened by 17% and 5% during the three and six months ended June 30, 2022, compared to the same periods of 2021.

8. OTHER OPERATING RESULTS

General and Administrative

	Three months ended June 30		Six months ended June 30	
($millions, except as indicated)	**2022**	**2021**	**2022**	**2021**
General and administrative expense	**$ 15**	$ 13	**$ 29**	$ 27
General and administrative expense per barrel of production	**$ 2.37**	$ 1.56	**$ 1.92**	$ 1.66
Bitumen production – bbls/d	**67,256**	91,803	**84,099**	91,326

General and administrative ("G&A") expense during the three and six months ended June 30, 2022 saw an increase from the same periods of 2021 primarily due to increased staff costs. G&A expense per barrel of production increased due to fixed costs being spread over lower bitumen production volumes.

Depletion and Depreciation

	Three months ended June 30		Six months ended June 30	
($millions, except as indicated)	**2022**	**2021**	**2022**	**2021**
Depletion and depreciation expense	**$ 87**	$ 108	**$ 211**	$ 216
Depletion and depreciation expense per barrel of production	**$ 14.35**	$ 12.99	**$ 13.89**	$ 13.07
Bitumen production – bbls/d	**67,256**	91,803	**84,099**	91,326

Total depletion and depreciation expense decreased during the three and six months ended June 30, 2022, compared to the same periods of 2021, primarily due to the decrease in production as depletion and depreciation expense for the Corporation's field production assets are depreciated on a unit of production basis.

On a per barrel basis, depletion and depreciation expense increased as a result of the impact of higher average future development costs and lower production volumes.

Commodity Risk Management Gain (Loss)

From time to time, the Corporation enters into financial commodity risk management contracts to protect and increase the predictability of the Corporation's cash flow, to manage commodity input costs and to support marketing asset optimization activities. 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.

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Realized:				
Crude oil contracts[1]	**$ —**	$ (95)	**$ —**	$ (174)
Condensate contracts[2]	**—**	6	**—**	17
Natural gas contracts[3]	**2**	1	**3**	2
Marketing asset optimization contracts[4]	**(1)**	1	**(1)**	(1)
Realized commodity risk management gain (loss)	**$ 1**	$ (87)	**$ 2**	$ (156)
Unrealized:				
Crude oil contracts[1]	**$ —**	$ (18)	**$ —**	$ (105)
Condensate contracts[2]	**6**	(14)	**5**	(19)
Natural gas contracts[3]	**(2)**	8	**3**	11
Marketing asset optimization contracts[4]	**4**	(3)	**4**	(2)
Unrealized commodity risk management gain (loss)	**$ 8**	$ (27)	**$ 12**	$ (115)
Commodity risk management gain (loss)	**$ 9**	$ (114)	**$ 14**	$ (271)

(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.
(4) The Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months to support marketing asset optimization activities.

During the three and six months ended June 30, 2022 the Corporation recognized a $9 million and $14 million net gain from commodity risk management, respectively, compared to a $114 million and $271 million net loss from commodity risk management, respectively, during the same periods of 2021, primarily due to the Corporation holding minimal commodity risk management contracts in 2022 compared to 2021. Crude oil contracts held in 2022 are directly related to the purchase and sale of third party products to facilitate asset optimization activities, which require the elimination of price risk pursuant to policies approved by the Corporation's Board of Directors. The elimination of price risk on certain marketing asset optimization activities was achieved through commodity risk management contracts.

The following table provides further details regarding the realized commodity risk management gain (loss):

	Three months ended June 30		Six months ended June 30	
(US$/bbl, unless otherwise indicated)	**2022**	**2021**	**2022**	**2021**
WTI fixed price contracts[(1)]:				
Average fixed price	**$ —**	$ 46.22	**$ —**	$ 46.92
Average settlement price	**—**	66.06	**—**	60.96
Gain (loss) on WTI fixed price contracts	**$ —**	$ (19.84)	**$ —**	$ (14.04)
WTI:WCS fixed differential contracts:				
Average fixed differential	**$ —**	$ (12.26)	**$ —**	$ (12.46)
Average settlement differential	**—**	(11.40)	**—**	(11.41)
Gain (loss) on WTI:WCS fixed differential contracts	**$ —**	$ (0.86)	**$ —**	$ (1.05)
Condensate purchase contracts:				
Average fixed differential[(2)]	**$ (11.30)**	$ (9.74)	**$ (11.30)**	$ (10.03)
Average settlement differential	**(17.43)**	(5.08)	**(9.52)**	(3.55)
Gain (loss) on condensate purchase contracts	**$ (6.13)**	$ 4.66	**$ 1.78**	$ 6.48
Natural gas purchase contracts:				
Average fixed price (C$/GJ)	**$ 2.50**	$ 2.60	**$ 2.50**	$ 2.61
Average settlement price (C$/GJ)	**6.86**	2.93	**5.68**	2.94
Gain (loss) on natural gas purchase contracts (C$/GJ)	**$ 4.36**	$ 0.33	**$ 3.18**	$ 0.33

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

(2) *Condensate purchase contracts fix the condensate price at Mont Belvieu, Texas relative to WTI.*

Stock-based Compensation

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Cash-settled expense	**$ 11**	$ 17	**$ 55**	$ 36
Equity-settled expense	**6**	5	**10**	7
Equity price risk management gain[(1)]	**(3)**	(18)	**(45)**	(37)
Stock-based compensation expense	**$ 14**	$ 4	**$ 20**	$ 6

(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.*

During the three months ended June 30, 2022 cash-settled expense decreased primarily due to the decrease in outstanding cash-settled restricted share units partially offset by the increase in the Corporation's share price as compared to the same period of 2021. The increase in cash-settled expense during the six months ended June 30, 2022 was primarily due to the increase in the Corporation's share price. The Corporation's common share price increased to $17.82 per share as at June 30, 2022, from its value of $17.07 per share as at March 31, 2022 and $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 and six months ended June 30, 2022, equity price risk management gains of $3 million and $45 million, respectively, were recognized on the increase in share price during these periods compared to gains of $18 million and $37 million, respectively, during the same periods of 2021.

Foreign Exchange Gain (Loss), Net

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ (73)**	$ 38	**$ (42)**	$ 86
US$ denominated cash and cash equivalents	**14**	3	**5**	(2)
Foreign currency risk management contracts	**—**	—	**7**	—
Unrealized net gain (loss) on foreign exchange	**(59)**	41	**(30)**	84
Realized gain (loss) on foreign exchange	**(1)**	—	**(2)**	—
Foreign exchange gain (loss), net	**$ (60)**	$ 41	**$ (32)**	$ 84
C$ equivalent of 1 US$				
Beginning of period	**1.2508**	1.2572	**1.2656**	1.2755
End of period	**1.2872**	1.2405	**1.2872**	1.2405

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.

During the three and six months ended June 30, 2022, the Canadian dollar weakened relative to the U.S. dollar by 3% and 2%, respectively, resulting in an unrealized foreign exchange loss of $59 million and $30 million, respectively.

During the three and six months ended June 30, 2021, the Canadian dollar strengthened by 1% and 3%, respectively, resulting in an unrealized foreign exchange gain of $41 million and $84 million, respectively.

Net Finance Expense

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Interest expense on long-term debt	**$ 43**	$ 53	**$ 90**	$ 111
Interest expense on lease liabilities	**6**	7	**12**	13
Interest income	**(1)**	—	**(1)**	—
Net interest expense	**48**	60	**101**	124
Debt extinguishment expense	**12**	5	**12**	5
Accretion on provisions	**2**	2	**4**	4
Net finance expense	**$ 62**	$ 67	**$ 117**	$ 133
Average effective interest rate	**6.7%**	6.7%	**6.7%**	6.7%

Interest expense on long-term debt decreased during the three and six months ended June 30, 2022, compared to the same periods of 2021, primarily as a result of debt reduction of US$704 million since the end of the second quarter of 2021.

For the three and six months ended June 30, 2022, debt extinguishment expense of $12 million was recognized in association with the repurchase and extinguishment of US$208 million (approximately C$268 million) of its 7.125% senior unsecured notes which included a cumulative debt redemption premium of $9 million and associated unamortized deferred debt issue costs of $3 million. Refer to Note 6 of the interim consolidated financial statements for further details.

Income Tax

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Earnings (loss) before income taxes	**$ 317**	$ 83	**$ 783**	$ 47
Effective tax rate	**29 %**	18 %	**25 %**	(8)%
Income tax expense (recovery)	**$ 92**	$ 15	**$ 196**	$ (4)

As at June 30, 2022, the Corporation had approximately $6.3 billion of available Canadian tax pools, including $4.7 billion of non-capital losses and $0.3 billion of capital losses, and recognized a deferred income tax asset of $100 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

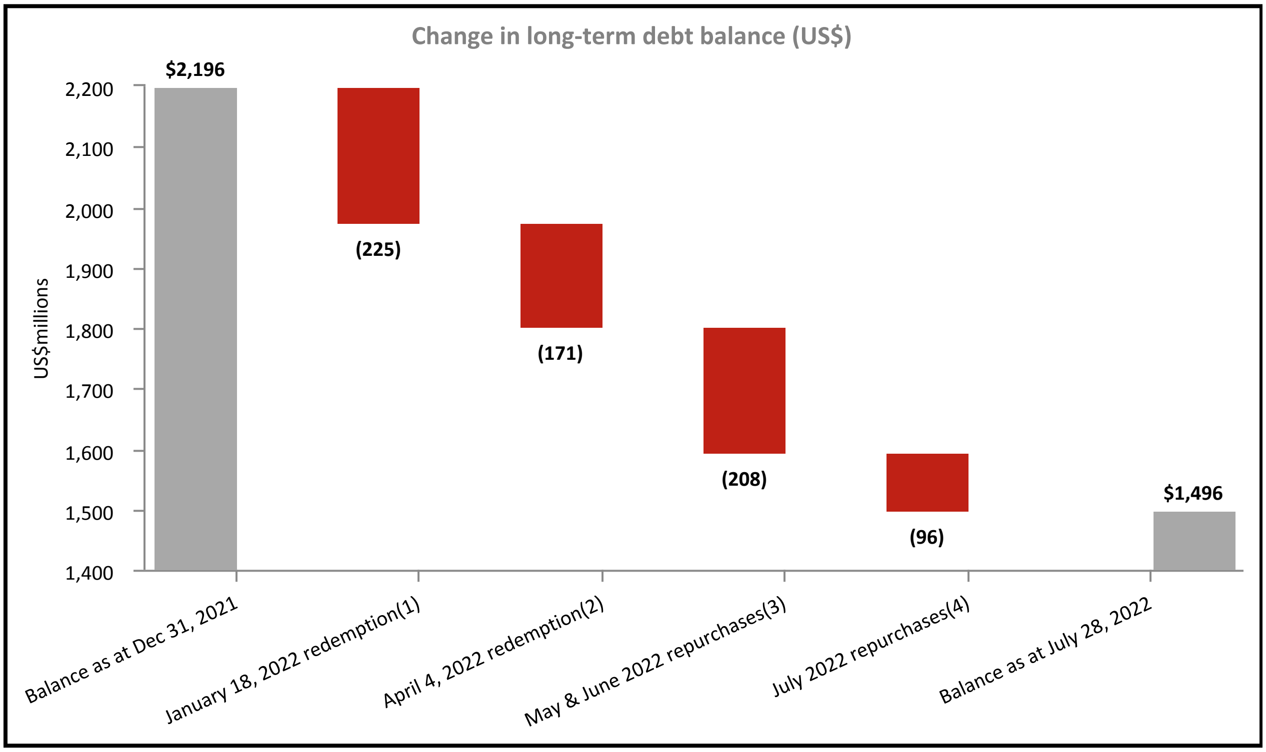
The effective tax rate for the three and six months ended June 30, 2022 differed from the Canadian statutory rate of 23% primarily due to the tax effect of foreign exchange gains and losses on the Corporation's long-term debt which is denominated in U.S. dollars.

10. LIQUIDITY AND CAPITAL RESOURCES

($millions)	**June 30, 2022**	**December 31, 2021**
Second Lien:		
6.50% senior secured second lien notes (June 30, 2022 - nil; fully redeemed April 4, 2022; December 31, 2021 - US$396 million)	**$ —**	$ 501
Unsecured:		
7.125% senior unsecured notes (June 30, 2022 - US$992 million; due 2027; December 31, 2021 - US$1.2 billion)	**1,277**	1,519
5.875% senior unsecured notes (June 30, 2022 - US$600 million; due 2029; December 31, 2021 - US$600 million)	**772**	759
Debt redemption premium	**—**	8
Unamortized deferred debt discount and debt issue costs	**(23)**	(25)
Current and long-term debt	**2,026**	2,762
Cash and cash equivalents	**(244)**	(361)
Net debt - C$[1]	**$ 1,782**	$ 2,401
Net debt - US$[1]	**$ 1,384**	$ 1,897

(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 17 of the interim consolidated financial statements.

The Corporation redeemed, repurchased and extinguished 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.

(3) Weighted average repurchase price of 103.2% plus accrued and unpaid interest on US$208 million of the Corporation's 7.125% senior unsecured notes due 2027.

(4) For the period July 1 to July 27, 2022, weighted average repurchase price of 101% plus accrued and unpaid interest on US$96 million of the Corporation's 7.125% senior unsecured notes due 2027.

The Corporation's cash and cash equivalents balance was $244 million as at June 30, 2022 compared to $361 million as at December 31, 2021. Refer to the "Cash Flow Summary" section for further details.

The Corporation reached its net debt target of US$1.7 billion during the second quarter of 2022. As a result, the Corporation allocated approximately 25% of free cash flow generated to share buybacks with the remaining free cash flow applied to ongoing debt reduction which will continue until the Corporation’s net debt reaches US$1.2 billion. 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.

The Corporation has total available credit under two facilities of $1.2 billion, comprised of $600 million under the revolving credit facility and $600 million under a letter of credit facility guaranteed by EDC. 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 October 31, 2026. The revolving credit facility and EDC Facility 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 by targeting sales to primarily investment grade customers in the energy industry. The Corporation's earliest maturing long-term debt is approximately 4.5 years out, represented by US$992 million of senior unsecured notes due February 2027. Additionally, the Corporation's modified covenant-lite $600 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $300 million. If drawn in excess of $300 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 June 30, 2022, the Corporation had $596 million of unutilized capacity under the $600 million revolving credit facility and the Corporation had $170 million of unutilized capacity under the $600 million EDC Facility. A letter of credit of $4 million remains outstanding under the revolving credit facility as at June 30, 2022. Letters of credit issued under the revolving credit facility or EDC 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

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Net cash provided by (used in):				
Operating activities	**$ 611**	$ 180	**$ 928**	$ 192
Investing activities	**(92)**	(73)	**(180)**	(122)
Financing activities	**(578)**	(5)	**(869)**	(22)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**13**	3	**4**	(3)
Change in cash and cash equivalents	**$ (46)**	$ 105	**$ (117)**	$ 45

Cash Flow – Operating Activities

Net cash provided by operating activities for the three and six months ended June 30, 2022 increased, compared to the same periods of 2021, primarily due to higher benchmark crude oil prices partially offset by lower bitumen sales volumes in 2022 associated with the major planned turnaround.

Cash Flow – Investing Activities

Net cash used in investing activities increased during the three and six months ended June 30, 2022, compared to the same periods of 2021, reflecting increased capital spending primarily reflecting the major planned turnaround.

Cash Flow – Financing Activities

Net cash used in financing activities for the three and six months ended June 30, 2022 increased, compared to the same periods of 2021, primarily due to the debt redemptions, note repurchases and extinguishments and repurchases of the Corporation's common shares during the three and six months ended June 30, 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. Financial commodity risk management contracts are also used to eliminate price risk on marketing asset optimization activities pursuant to Board approved policies.

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 June 30, 2022:

As at June 30, 2022			
Condensate Purchase Contracts	**Volumes (bbls/d)**	**Term**	**Average Price (US$/bbl)**
WTI:Mont Belvieu Fixed Differential	200	Jul 1, 2022 - Dec 31, 2022	$(11.30)
WTI:Mont Belvieu Fixed Differential	7,000	Jan 1, 2023 - Oct 31, 2023	$(11.54)
Natural Gas Purchase Contracts	**Volumes (GJ/d)**	**Term**	**Average Price (C$/GJ)**
AECO Fixed Price	5,000	Jul 1, 2022 - Dec 31, 2023	$2.50

Incremental to these commodity risk management contracts, the Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months to support marketing asset optimization activities.

The Corporation entered into the following financial commodity risk management contract relating to condensate purchases between June 30, 2022 and July 28, 2022:

Subsequent to June 30, 2022			
Condensate Purchase Contracts	**Volumes (bbls/d)**	**Term**	**Average Price (US$/bbl)**
WTI:Mont Belvieu Fixed Differential	1,500	Jan 1, 2023 - Oct 31, 2023	$(11.03)

The following table summarizes the sensitivity of cash operating netback, adjusted funds flow and earnings (loss) before income tax of fluctuating commodity prices on the Corporation’s open financial commodity risk management positions in place as at June 30, 2022:

Commodity	**Sensitivity Range**	**Increase**	**Decrease**
Condensate purchase price	± 5% in condensate price as a percentage of WTI	**$ 12**	**$ (12)**
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	**$ 1**	**$ (1)**

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 related to the Corporation's stock-based compensation program. 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 the cash-settled components of 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 any realized asset outstanding at period-end is included in trade receivables and other on the balance sheet.

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Unrealized equity price risk management (gain) loss	**$ (3)**	$ (18)	**$ 1**	$ (29)
Realized equity price risk management (gain) loss	**—**	—	**(46)**	(8)
Equity price risk management (gain) loss	**$ (3)**	$ (18)	**$ (45)**	$ (37)

12. SHARES OUTSTANDING

As at June 30, 2022, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	**Units**
Common shares	**307.3**
Convertible securities	
Stock options(1)	**0.3**
Equity-settled RSUs and PSUs	**5.1**

(1) 0.3 million stock options were exercisable as at June 30, 2022.

As at July 27, 2022, the Corporation had 304.5 million common shares, 0.3 million stock options and 5.2 million equity-settled RSUs and equity-settled PSUs outstanding, and 0.3 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 June 30, 2022. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities 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**
Commitments:							
Transportation and storage(1)	$ 212	$ 431	$ 456	$ 431	$ 410	$ 5,430	$ 7,370
Diluent purchases	93	31	—	—	—	—	124
Other operating commitments	8	16	14	13	13	24	88
Variable office lease costs	2	5	5	5	5	23	45
Capital commitments	23	—	—	—	—	—	23
Total Commitments	338	483	475	449	428	5,477	7,650
Other Obligations:							
Lease obligations	23	38	37	29	29	463	619
Current and long-term debt(2)	—	—	—	—	—	2,049	2,049
Interest on long-term debt(2)	68	136	136	136	136	108	720
Decommissioning obligation(3)	3	6	5	5	5	767	791
Total Commitments and Obligations	**$ 432**	**$ 663**	**$ 653**	**$ 619**	**$ 598**	**$ 8,864**	**$ 11,829**

(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 unsecured notes and associated interest payments based on interest and foreign exchange rates in effect on June 30, 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 consolidated 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 non-recurring adjustments, 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 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.

In the second quarter of 2022, an adjustment was made to the presentation of adjusted funds flow and free cash flow. In April 2020, the Corporation issued cash-settled RSUs under its long-term incentive ("LTI") plan when the Corporation's share price was at a historic low of $1.57 per share. Concurrent with the issuance, the Corporation entered into equity price risk management contracts to manage share price volatility in the three-year period following the issuance, effectively eliminating cash flow risk associated with share price appreciation over that time period. The significant increase in the Corporation's share price from April 2020 to June 30, 2022 resulted in the recognition of a significant cash-settled stock-based compensation expense, which was previously included as a component of adjusted funds flow and free cash flow. Since the actual cash impact of the 2020 cash-settled RSUs is subject to equity price risk management contracts, there is no cash impact over the term of these RSUs beyond the value at the date of issue of $1.57 per share.

As a result of the equity risk management contracts, the Corporation's operating performance and cash flow generating ability are not impacted by the April 2020 cash-settled RSUs issued and the associated equity price risk management contracts, therefore the financial statement impacts of the cash-settled stock-based compensation associated with the April 2020 issuance and the equity price risk management contracts have been excluded from Adjusted Funds Flow and Free Cash Flow. All prior periods presented have been adjusted to reflect this change in presentation. The adjustments to prior periods are as follows:

	2022	2021				2020		
($millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Adjusted funds flow, as previously presented	**$ 587**	$ 266	$ 239	$ 166	$ 127	$ 84	$ 26	$ 89
Adjustments:								
Impact of cash-settled SBC units subject to equity price risk management	**18**	8	4	18	5	4	—	2
Realized equity price risk management gain	**(46)**	—	—	—	(8)	—	—	—
Adjusted funds flow, current presentation	**$ 559**	$ 274	$ 243	$ 184	$ 124	$ 88	$ 26	$ 91
Free cash flow, as previously presented	**$ 499**	$ 160	$ 155	$ 95	$ 57	$ 44	$ (9)	$ 69
Adjustments:								
Impact of cash-settled SBC units subject to equity price risk management	**18**	8	4	18	5	4	—	2
Realized equity price risk management gain	**(46)**	—	—	—	(8)	—	—	—
Free cash flow, current presentation	**$ 471**	$ 168	$ 159	$ 113	$ 54	$ 48	$ (9)	$ 71

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

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Funds flow from operating activities	**$ 412**	$ 160	**$ 999**	$ 281
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management	**66**	18	**85**	23
Realized equity price risk management gain	**—**	—	**(46)**	(8)
Payments on onerous contract	**—**	6	**—**	12
Adjusted funds flow	**478**	184	**1,038**	308
Capital expenditures	**(104)**	(71)	**(192)**	(141)
Free cash flow	**$ 374**	$ 113	**$ 846**	$ 167

Net Debt

Net debt is a capital management measure and is defined in the Corporation's consolidated 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	**June 30, 2022**	**December 31, 2021**
Long-term debt	**$ 2,026**	$ 2,477
Current portion of long-term debt	**—**	285
Cash and cash equivalents	**(244)**	(361)
Net debt - C$	**$ 1,782**	$ 2,401
Net debt - US$	**$ 1,384**	$ 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:

	Three months ended June 30		Six months ended June 30	
($millions)	**2022**	**2021**	**2022**	**2021**
Revenues	**$ 1,571**	$ 1,009	**$ 3,102**	$ 1,923
Diluent expense	**(415)**	(324)	**(932)**	(620)
Transportation and storage expense	**(130)**	(91)	**(248)**	(184)
Purchased product	**(376)**	(184)	**(536)**	(369)
Operating expenses	**(107)**	(67)	**(211)**	(133)
Realized gain (loss) on commodity risk management	**1**	(87)	**2**	(156)
Cash operating netback	**$ 544**	$ 256	**$ 1,177**	$ 461

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.

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 blend sales and bitumen realization. A reconciliation from revenues to blend sales and bitumen realization has been provided below:

	Three months ended June 30				Six months ended June 30			
	2022		**2021**		**2022**		**2021**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Revenues	**$ 1,571**		$ 1,009		**$ 3,102**		$ 1,923	
Other revenue	**(22)**		(23)		**(46)**		(51)	
Royalties	**58**		14		**105**		21	
Petroleum revenue	**1,607**		1,000		**3,161**		1,893	
Purchased product	**(376)**		(184)		**(536)**		(369)	
Blend sales	**1,231**	**$ 128.20**	816	$ 69.27	**2,625**	**$ 115.23**	1,524	$ 65.32
Diluent expense	**(415)**	**(5.51)**	(324)	(9.18)	**(932)**	**(7.16)**	(620)	(9.02)
Bitumen realization	**$ 816**	**$ 122.69**	$ 492	$ 60.09	**$ 1,693**	**$ 108.07**	$ 904	$ 56.30

Net Transportation and Storage

Net transportation and storage 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 June 30				Six months ended June 30			
	2022		2021		2022		2021	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Transportation and storage expense	**$ (130)**	**$ (19.57)**	$ (91)	$ (11.15)	**$ (248)**	**$ (15.86)**	$ (184)	$ (11.48)
Other revenue	**$ 22**		$ 23		**$ 46**		$ 51	
Less power revenue	**(21)**		(21)		**(44)**		(46)	
Transportation revenue	**$ 1**	**$ 0.17**	$ 2	$ 0.24	**$ 2**	**$ 0.16**	$ 5	$ 0.33
Net transportation and storage	**$ (129)**	**$ (19.40)**	$ (89)	$ (10.91)	**$ (246)**	**$ (15.70)**	$ (179)	$ (11.15)

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 June 30				Six months ended June 30			
	2022		2021		2022		2021	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Non-energy operating costs	**$ (38)**	**$ (5.65)**	$ (31)	$ (3.84)	**$ (80)**	**$ (5.13)**	$ (63)	$ (3.94)
Energy operating costs	**(69)**	**(10.40)**	(36)	(4.27)	**(131)**	**(8.33)**	(70)	(4.30)
Operating expenses	**$ (107)**	**$ (16.05)**	$ (67)	$ (8.11)	**$ (211)**	**$ (13.46)**	$ (133)	$ (8.24)
Other revenue	**$ 22**		$ 23		**$ 46**		$ 51	
Less transportation revenue	**(1)**		(2)		**(2)**		(5)	
Power revenue	**$ 21**	**$ 3.08**	$ 21	$ 2.57	**$ 44**	**$ 2.78**	$ 46	$ 2.85
Operating expenses net of power revenue	**$ (86)**	**$ (12.97)**	$ (46)	$ (5.54)	**$ (167)**	**$ (10.68)**	$ (87)	$ (5.39)

Effective royalty rate

Effective royalty rate is a non-GAAP financial ratio. Its terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial ratio should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Effective royalty rate is a measure of the Corporation’s royalty rate to enable a comparison between pre- and post-payout Crown royalties by calculating a royalty rate on a consistent basis. The actual royalty rate applied will differ from the effective royalty rate.

The effective royalty rate is calculated as royalty expense divided by bitumen realization (non-GAAP measure) less transportation and storage expense.

	Three months ended June 30		Six months ended June 30	
($millions)	2022	2021	2022	2021
Bitumen realization	**$ 816**	$ 492	**$ 1,693**	$ 904
Transportation and storage expense	**(130)**	(91)	**(248)**	(184)
	$ 686	$ 401	**$ 1,445**	$ 720
Royalties	**$ 58**	$ 14	**$ 105**	$ 21
Effective royalty rate	**8.5 %**	3.5 %	**7.3 %**	2.9 %

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 and is also available on the SEDAR website at 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

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

Measurement

bbl	barrel
bbls/d	barrels per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
MW	megawatts
MW/h	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 Corporation’s expectation that the combination of the three oil sands industry groups will enhance the Pathways Alliance’s collaborative efforts to advance responsible oil sands development and to progress on the Alliances’ goals for responsible development, including achieving net zero greenhouse gas emissions from oil sands production; the Corporation’s expectation that the Christina Lake Facility has returned to full production as at June 30, 2022; the Corporation’s expectation that incremental capital included in sustaining and maintenance activities will allow the Corporation to fully utilize the Christina Lake central plant facility's oil processing capacity of approximately 100,000 bbls/d; the Corporation’s expectation that the Christina Lake operation will reach payout for royalty purposes in the fourth quarter of 2022; all statements relating to the Corporation’s revised 2022 guidance, including its full year production, non-energy operating costs, G&A expense, capital expenditures and transportation costs and all statements relating to the Corporation’s effective royalty rate; the Corporation’s expectation of selling 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’s expectation of allocating 25% of free cash flow to share buybacks with the remaining cash flow applied to ongoing debt reduction until it reaches its near-term debt target of US$1.2 billion; the Corporation’s expectation that once the US$1.2 billion net debt target is reached the percentage of free cash flow allocated to share buybacks will increase to approximately 50% with the remaining cash flow applied to further debt reduction until it reaches a net debt floor of US$600 million at which time the Corporation expects to allocate 100% of free cash flow to shareholders; the Corporation’s continued focus on debt reduction as a key component of its capital allocation strategy in 2022; 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.

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 and is also available on SEDAR at www.sedar.com.

22. QUARTERLY SUMMARIES

	2022		2021				2020	
Unaudited	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**225**	362	177	54	68	(17)	16	(9)
Per share, diluted	**0.72**	1.15	0.57	0.17	0.22	(0.06)	0.05	(0.03)
Funds flow from operating activities	**412**	587	260	212	160	121	81	19
Per share, diluted	**1.31**	1.87	0.83	0.68	0.51	0.39	0.26	0.06
Adjusted funds flow(1)	**478**	559	274	243	184	124	88	26
Per share, diluted(1)	**1.52**	1.78	0.88	0.78	0.59	0.40	0.29	0.09
Capital expenditures	**104**	88	106	84	71	70	40	35
Working capital	**437**	465	150	199	127	8	55	131
Net debt - C$(1)	**1,782**	2,150	2,401	2,559	2,661	2,798	2,798	2,981
Net debt - US$(1)	**1,384**	1,722	1,897	2,007	2,145	2,226	2,194	2,237
Shareholders' equity	**4,339**	4,178	3,808	3,628	3,564	3,491	3,506	3,495
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**108.41**	94.29	77.19	70.56	66.07	57.84	42.66	40.93
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.80)**	(14.53)	(14.64)	(13.58)	(11.49)	(12.47)	(9.30)	(9.09)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(14.25)**	(16.35)	(16.40)	(15.13)	(13.11)	(14.22)	(10.56)	(10.48)
AWB – Edmonton (US$/bbl)	**94.16**	77.94	60.79	55.43	52.96	43.62	32.10	30.45
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(6.15)**	(5.85)	(6.40)	(5.57)	(3.92)	(2.52)	(2.83)	(3.20)
AWB – U.S. Gulf Coast (US$/bbl)	**102.26**	88.44	70.79	64.99	62.15	55.32	39.83	37.73
Enbridge Mainline heavy apportionment	**— %**	10 %	21 %	53 %	46 %	48 %	22 %	9 %
C$ equivalent of 1US$ – average	**1.2766**	1.2661	1.2600	1.2602	1.2280	1.2663	1.3031	1.3316
Natural gas – AECO ($/mcf)	**7.89**	5.16	5.07	3.92	3.37	3.43	2.88	2.48
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**105,517**	146,382	141,280	127,546	129,474	128,236	136,623	93,479
Diluent usage – bbls/d	**(32,426)**	(46,196)	(42,386)	(35,295)	(39,494)	(40,938)	(40,892)	(25,910)
Bitumen sales – bbls/d	**73,091**	100,186	98,894	92,251	89,980	87,298	95,731	67,569
Bitumen production – bbls/d	**67,256**	101,128	100,698	91,506	91,803	90,842	91,030	71,516
Steam-oil ratio (SOR)	**2.46**	2.43	2.42	2.56	2.39	2.37	2.31	2.36
Blend sales(2)	**128.20**	105.79	82.43	74.54	69.27	61.28	45.75	45.44
Diluent expense	**(5.51)**	(8.51)	(11.37)	(9.63)	(9.18)	(8.94)	(7.11)	(5.76)
Bitumen realization(2)	**122.69**	97.28	71.06	64.91	60.09	52.34	38.64	39.68
Transportation & storage expense net of transportation revenue(2)	**(19.40)**	(12.97)	(11.39)	(10.03)	(10.91)	(11.41)	(14.11)	(18.55)
Curtailment	**—**	—	—	—	—	—	0.03	—
Royalties	**(8.67)**	(5.24)	(3.54)	(2.67)	(1.71)	(0.85)	(0.23)	(0.21)
Non-energy operating costs(3)	**(5.65)**	(4.74)	(4.56)	(4.46)	(3.84)	(4.05)	(4.70)	(3.96)
Energy operating costs(3)	**(10.40)**	(6.80)	(6.22)	(4.77)	(4.27)	(4.34)	(3.73)	(3.17)
Power revenue	**3.08**	2.56	2.58	2.06	2.57	3.14	1.45	1.08
Realized gain (loss) on commodity risk management	**0.10**	0.12	(10.06)	(7.73)	(10.63)	(8.80)	1.31	1.71
Cash operating netback(2)	**81.75**	70.21	37.87	37.31	31.30	26.03	18.66	16.58
Revenues	**1,571**	1,531	1,307	1,091	1,009	914	786	533
Power sales price (C$/MWh)	**117.94**	91.50	95.22	82.17	88.40	93.27	46.34	39.03
Power sales (MW/h)	**82**	121	117	101	113	128	125	78
Average cost of diluent ($/bbl of diluent)	**140.61**	124.23	108.96	99.69	90.18	80.34	62.37	60.48
Average cost of diluent as a % of WTI	**102 %**	104 %	112 %	112 %	111 %	110 %	112 %	111 %
Depletion and depreciation rate per bbl of production	**14.35**	13.58	13.63	12.78	12.99	13.15	12.64	13.33
General and administrative expense per bbl of production	**2.37**	1.61	1.58	1.72	1.56	1.77	1.65	1.50
COMMON SHARES								
Shares outstanding, end of period (000)	**307,271**	307,596	306,865	306,773	306,716	303,137	302,681	302,657
Common share price ($) - close (end of period)	**17.82**	17.07	11.70	9.89	8.97	6.53	4.45	2.77

(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$40.93/bbl to US$108.41/bbl. The volatility in 2020 was driven by the impact of COVID-19 on supply and demand fundamentals. Since then we have 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; and
- planned turnaround and other maintenance activities affecting production.

23. ANNUAL SUMMARIES

	2021	2020	2019	2018(1)	2017(1)	2016(1)	2015(1)
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	283	(357)	(62)	(119)	166	(429)	(1,170)
Per share, diluted	0.91	(1.18)	(0.21)	(0.40)	0.57	(1.90)	(5.21)
Funds flow from operating activities	753	239	741	169	343	(69)	34
Per share, diluted	2.42	0.78	2.46	0.56	1.18	(0.31)	0.15
Adjusted funds flow(2)	826	281	724	175	371	(63)	49
Per share, diluted(2)	2.65	0.92	2.41	0.58	1.28	(0.28)	0.22
Capital expenditures	331	149	198	622	508	140	314
Working capital	150	55	123	290	313	96	363
Net debt - C$(1)	2,401	2,798	2,917	3,422	4,205	4,897	4,782
Net debt - US$(1)	1,897	2,194	2,250	2,508	3,359	3,647	3,455
Shareholders' equity	3,808	3,506	3,853	3,886	3,964	3,287	3,678
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/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 ($/mcf)	3.95	2.43	1.92	1.62	2.29	2.25	2.71
OPERATIONAL **($/bbl unless specified)**							
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(3)	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(3)	62.47	27.23	53.21	36.69	42.03	27.91	30.71
Transportation & storage expense net of transportation revenue(3)	(10.93)	(12.92)	(10.84)	(8.42)	(6.89)	(6.46)	(4.82)
Curtailment	—	0.06	(0.37)	—	—	—	—
Royalties	(2.25)	(0.31)	(1.30)	(1.20)	(0.77)	(0.29)	(0.70)
Non-energy operating costs(4)	(4.24)	(4.38)	(4.61)	(4.62)	(4.62)	(5.62)	(6.54)
Energy operating costs(4)	(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(3)	33.37	19.22	32.15	17.61	27.14	13.25	15.80
Revenues	4,321	2,292	3,931	2,733	2,474	1,866	1,926
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
COMMON SHARES							
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.

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

As at	Note	June 30, 2022	December 31, 2021
Assets			
Current assets			
Cash and cash equivalents	14	$ **244**	$ 361
Trade receivables and other		**583**	496
Inventories		**240**	157
Risk management	16	**84**	36
		1,151	1,050
Non-current assets			
Property, plant and equipment	3	**5,867**	5,878
Exploration and evaluation assets	4	**126**	126
Other assets	5	**201**	202
Risk management	16	**5**	41
Deferred income tax asset	13	**100**	296
Total assets		$ **7,450**	$ 7,593
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		$ **629**	$ 500
Interest payable		**58**	80
Current portion of long-term debt	6	**—**	285
Current portion of provisions and other liabilities	7	**27**	27
Risk management	16	**—**	7
		714	899
Non-current liabilities			
Long-term debt	6	**2,026**	2,477
Provisions and other liabilities	7	**371**	409
Total liabilities		**3,111**	3,785
Shareholders' equity			
Share capital	8	**5,451**	5,486
Contributed surplus		**162**	172
Deficit		**(1,302)**	(1,875)
Accumulated other comprehensive income		**28**	25
Total shareholders' equity		**4,339**	3,808
Total liabilities and shareholders' equity		$ **7,450**	$ 7,593

Commitments and contingencies (Note 18)
The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

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

		Three months ended June 30		Six months ended June 30	
	Note	**2022**	**2021**	**2022**	**2021**
Revenues					
Petroleum revenue, net of royalties	10	**$ 1,549**	$ 986	**$ 3,056**	$ 1,872
Other revenue	10	**22**	23	**46**	51
Revenues		**1,571**	1,009	**3,102**	1,923
Expenses					
Diluent expense		**415**	324	**932**	620
Transportation and storage expense		**130**	91	**248**	184
Operating expenses		**107**	67	**211**	133
Purchased product		**376**	184	**536**	369
Depletion and depreciation	3, 5	**87**	108	**211**	216
General and administrative		**15**	13	**29**	27
Stock-based compensation	9	**14**	4	**20**	6
Net finance expense	12	**62**	67	**117**	133
Inventory impairment		**—**	(1)	**—**	5
Gain on asset dispositions	5	**(3)**	(4)	**(3)**	(4)
Commodity risk management (gain) loss, net	16	**(9)**	114	**(14)**	271
Foreign exchange (gain) loss, net	11	**60**	(41)	**32**	(84)
Earnings before income taxes		**317**	83	**783**	47
Income tax expense (recovery)	13	**92**	15	**196**	(4)
Net earnings		**225**	68	**587**	51
Other comprehensive income (loss), net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**5**	(2)	**3**	(5)
Comprehensive income		**$ 230**	$ 66	**$ 590**	$ 46
Net earnings per common share					
Basic	15	**$ 0.73**	$ 0.22	**$ 1.90**	$ 0.17
Diluted	15	**$ 0.72**	$ 0.22	**$ 1.87**	$ 0.17

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**	**$**	**3,808**
Stock-based compensation		**—**		**11**		**—**		**—**		**11**
Stock options exercised		**34**		**(10)**		**—**		**—**		**24**
RSUs vested and released		**11**		**(11)**		**—**		**—**		**—**
Repurchase of shares for cancellation		**(80)**		**—**		**(14)**		**—**		**(94)**
Comprehensive income (loss)		**—**		**—**		**587**		**3**		**590**
Balance as at June 30, 2022	**$**	**5,451**	**$**	**162**	**$**	**(1,302)**	**$**	**28**	**$**	**4,339**
Balance as at December 31, 2020	$	5,460	$	177	$	(2,158)	$	27	$	3,506
Stock-based compensation		—		8		—		—		8
Stock options exercised		6		(2)		—		—		4
RSUs vested and released		19		(19)		—		—		—
Comprehensive income (loss)		—		—		51		(5)		46
Balance as at June 30, 2021	$	5,485	$	164	$	(2,107)	$	22	$	3,564

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 June 30		Six months ended June 30	
	Note	2022	2021	2022	2021
Cash provided by (used in):					
Operating activities					
Net earnings		**$ 225**	$ 68	**$ 587**	$ 51
Adjustments for:					
Deferred income tax expense (recovery)	13	**92**	17	**196**	(2)
Inventory impairment		**—**	(1)	**—**	5
Depletion and depreciation	3, 5	**87**	108	**211**	216
Stock-based compensation	9	**3**	(13)	**11**	(21)
Unrealized net (gain) loss on foreign exchange	11	**59**	(41)	**30**	(84)
Unrealized net (gain) loss on commodity risk management	16	**(8)**	27	**(12)**	115
Amortization of debt discount and debt issue costs		**(1)**	2	**1**	4
Gain on asset dispositions	5	**(3)**	(4)	**(3)**	(4)
Debt extinguishment expense	12	**12**	5	**12**	5
Other		**2**	2	**3**	3
Decommissioning expenditures	7	**1**	—	**(1)**	(2)
Payments on onerous contracts		**—**	(6)	**—**	(12)
Net change in long-term incentive compensation liability		**(57)**	(4)	**(36)**	7
Funds flow from operating activities		**412**	160	**999**	281
Net change in non-cash working capital items	14	**199**	20	**(71)**	(89)
Net cash provided (used in) by operating activities		**611**	180	**928**	192
Investing activities					
Capital expenditures	3	**(104)**	(71)	**(192)**	(141)
Net proceeds on dispositions		**3**	44	**3**	44
Other		**2**	—	**1**	—
Net change in non-cash working capital items	14	**7**	(46)	**8**	(25)
Net cash provided by (used in) investing activities		**(92)**	(73)	**(180)**	(122)
Financing activities					
Issuance of senior unsecured notes		**—**	—	**—**	769
Repayment and redemption of long-term debt	6	**(484)**	—	**(772)**	(763)
Debt redemption premium and refinancing costs	6	**(12)**	—	**(17)**	(19)
Repurchase of shares	8	**(94)**	—	**(94)**	—
Issue of shares, net of issue costs		**17**	2	**24**	4
Receipts on leased assets	14	**1**	—	**2**	1
Payments on leased liabilities	14	**(6)**	(7)	**(12)**	(14)
Net cash provided by (used in) financing activities		**(578)**	(5)	**(869)**	(22)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**13**	3	**4**	(3)
Change in cash and cash equivalents		**(46)**	105	**(117)**	45
Cash and cash equivalents, beginning of period		**290**	54	**361**	114
Cash and cash equivalents, end of period		**$ 244**	$ 159	**$ 244**	$ 159

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

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

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 July 28, 2022.

3. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Right-of-use assets	Corporate assets	Total
Cost					
Balance as at December 31, 2021	$ 9,611	$ 47	$ 286	$ 79	$ 10,023
Additions	193	—	1	—	194
Derecognition	—	—	(3)	—	(3)
Change in decommissioning liabilities	6	—	—	—	6
Balance as at June 30, 2022	**$ 9,810**	**$ 47**	**$ 284**	**$ 79**	**$ 10,220**
Accumulated depletion and depreciation					
Balance as at December 31, 2021	$ 3,998	$ 32	$ 61	$ 54	$ 4,145
Depletion and depreciation	198	—	11	2	211
Derecognition	—	—	(3)	—	(3)
Balance as at June 30, 2022	**$ 4,196**	**$ 32**	**$ 69**	**$ 56**	**$ 4,353**
Carrying amounts					
Balance as at December 31, 2021	$ 5,613	$ 15	$ 225	$ 25	$ 5,878
Balance as at June 30, 2022	**$ 5,614**	**$ 15**	**$ 215**	**$ 23**	**$ 5,867**

As at June 30, 2022, property, plant and equipment was assessed for indicators of impairment and none were identified.

4. 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 indicators of impairment and none were identified.

5. OTHER ASSETS

As at		June 30, 2022		December 31, 2021
Non-current pipeline linefill[a]	**$**	**177**	$	177
Finance sublease receivables		**13**		15
Intangible assets[b]		**4**		5
Prepaid transportation costs[c]		**8**		8
Pathways Initiative		**1**		—
		203		205
Less current portion, included in trade receivables and other		**(2)**		(3)
	$	**201**	$	202

a. 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.

b. As at June 30, 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 six months ended June 30, 2022 (year ended December 31, 2021 – $2 million). During the six months ended June 30, 2022, the Corporation sold internally generated emission performance credits that were recorded at a nominal amount, and recognized a gain on asset dispositions of $3 million.

c. 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.

6. LONG-TERM DEBT

As at		June 30, 2022		December 31, 2021
Second Lien:				
6.50% senior secured second lien notes (June 30, 2022 - nil; fully redeemed April 4, 2022; December 31, 2021 - US$396 million)[a]	**$**	**—**	$	501
Unsecured:				
7.125% senior unsecured notes (June 30, 2022 - US$992 million; due 2027; December 31, 2021 - US$1.2 billion)[b]		**1,277**		1,519
5.875% senior unsecured notes (June 30, 2022 - US$600 million; due 2029; December 31, 2021 - US$600 million)		**772**		759
		2,049		2,779
Debt redemption premium		**—**		8
Unamortized deferred debt discount and debt issue costs		**(23)**		(25)
	$	**2,026**	$	2,762
Less current portion of 6.50% senior secured second lien notes		**—**		(285)
	$	**2,026**	$	2,477

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2872 (December 31, 2021 – US$1 = C$1.2656).

a. On January 18, 2022, the Corporation redeemed US$225 million (approximately $288 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.

   On April 4, 2022, the Corporation redeemed the remaining outstanding balance of US$171 million (approximately $216 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.

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

b. During the three months ended June 30, 2022, the Corporation repurchased and extinguished US$208 million (approximately $268 million) of its 7.125% senior unsecured notes due February 2027 at a weighted average price of 103.2% plus accrued and unpaid interest. For the three and six months ended June 30, 2022, the Corporation recognized a cumulative debt redemption premium of $9 million and associated unamortized deferred debt issue costs of $3 million for debt extinguishment expense of $12 million recognized in net finance expense (Note 12).

   Subsequent to June 30, 2022, the Corporation has repurchased a further US$96 million (approximately $124 million) of the Corporation's outstanding 7.125% senior unsecured notes due February 2027 at a weighted average price of 101%.

7. PROVISIONS AND OTHER LIABILITIES

As at		June 30, 2022		December 31, 2021
Lease liabilities[(a)]	**$**	**254**	$	266
Decommissioning provision[(b)]		**144**		135
Long-term incentive compensation liability[(c)]		**—**		35
Provisions and other liabilities		**398**		436
Less current portion		**(27)**		(27)
Non-current portion	**$**	**371**	$	409

a. Lease liabilities:

As at		June 30, 2022		December 31, 2021
Balance, beginning of period	**$**	**266**	$	286
Additions		**—**		8
Payments		**(24)**		(54)
Interest expense		**12**		26
Balance, end of period		**254**		266
Less current portion		**(20)**		(22)
Non-current portion	**$**	**234**	$	244

The Corporation's minimum lease payments are as follows:

As at June 30		2022
Within one year	$	43
Later than one year but not later than five years		134
Later than five years		454
Minimum lease payments		631
Amounts representing finance charges		(377)
Net minimum lease payments	$	254

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 June 30, 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		June 30, 2022		December 31, 2021
Balance, beginning of period	$	135	$	96
Changes in estimated life and estimated future cash flows		4		5
Changes in discount rates		2		29
Liabilities settled		(1)		(3)
Accretion		4		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 $792 million (December 31, 2021 – $799 million). As at June 30, 2022, the Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 9.0% (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 June 30, 2022, the Corporation recognized a liability of $85 million, all of which is recognized as current within accounts payable and accrued liabilities, relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2021 – $82 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 16 for further details.

8. SHARE CAPITAL

Common shares are classified as equity. Transaction costs directly attributable to the issuance of shares are recognized as a reduction of shareholders' equity, net of any related income tax. When the Corporation repurchases its own common shares, share capital is reduced by the average carrying value of the shares repurchased. If the average carrying value of the shares exceeds the purchase price, the difference will be recognized as contributed surplus. If the purchase price exceeds the average carrying value of the shares, any previous contributed surplus related to such transactions is reversed. To the extent there is none, the difference is recognized as a reduction to retained earnings.

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:

	Six months ended June 30, 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	**1,986**	**34**	939	7
Issued upon vesting and release of RSUs and PSUs	**2,867**	**11**	3,245	19
Repurchase of shares for cancellation	**(4,447)**	**(80)**	—	—
Balance, end of period	**307,271**	**$ 5,451**	306,865	$ 5,486

On March 7, 2022, the Corporation received approval from the Toronto Stock Exchange for a normal course issuer bid ("NCIB") which allows 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 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 the Corporation.

During the three months ended June 30, 2022, the Corporation purchased for cancellation 4.45 million common shares under its NCIB at a weighted average price of $21.14 for a total cost of $94 million. Share capital was reduced by the average carrying value of the shares of $17.98 per share, with the remaining cost recognized as a reduction to retained earnings.

Subsequent to June 30, 2022, the Corporation has purchased for cancellation a further 2.79 million common shares for a total cost of $45 million.

During 2022, the Corporation issued approximately 2 million common shares upon exercise of stock options and issued approximately 3 million common shares upon vesting and release of RSUs and PSUs.

9. STOCK-BASED COMPENSATION

	Three months ended June 30		Six months ended June 30	
	2022	**2021**	**2022**	**2021**
Cash-settled expense[(i)]	**$ 11**	$ 17	**$ 55**	$ 36
Equity-settled expense	**6**	5	**10**	7
Realized equity price risk management (gain) loss[(ii)]	**—**	—	**(46)**	(8)
Unrealized equity price risk management (gain) loss[(ii)]	**(3)**	(18)	**1**	(29)
Stock-based compensation	**$ 14**	$ 4	**$ 20**	$ 6

(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 16(d) for further details.

A $55 million cash-settled expense was recognized during the six months ended June 30, 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 June 30, 2022, and higher expense for the six months ended June 30, 2022 compared to the prior period. As at June 30, 2022, the Corporation recognized a liability of $85 million, all of which is recognized as current within accounts payable and accrued liabilities, relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2021 – $82 million).

10. REVENUES

	Three months ended June 30		Six months ended June 30	
	2022	**2021**	**2022**	**2021**
Sales from:				
Production	**$ 1,224**	$ 813	**$ 2,617**	$ 1,508
Purchased product[(i)]	**383**	187	**544**	385
Petroleum revenue	**$ 1,607**	$ 1,000	**$ 3,161**	$ 1,893
Royalties	**(58)**	(14)	**(105)**	(21)
Petroleum revenue, net of royalties	**$ 1,549**	$ 986	**$ 3,056**	$ 1,872
Power revenue	**$ 21**	$ 21	**$ 44**	$ 46
Transportation revenue	**1**	2	**2**	5
Other revenue	**$ 22**	$ 23	**$ 46**	$ 51
Revenues	**$ 1,571**	$ 1,009	**$ 3,102**	$ 1,923

(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 June 30					
	2022			2021		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	**Third-party**	**Total**	**Proprietary**	**Third-party**	**Total**
Country:						
Canada	**$ 230**	**$ 31**	**$ 261**	$ 411	$ —	$ 411
United States	**994**	**352**	**1,346**	402	187	589
	$ 1,224	**$ 383**	**$ 1,607**	$ 813	$ 187	$ 1,000

	Six months ended June 30					
	2022			2021		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	**Third-party**	**Total**	**Proprietary**	**Third-party**	**Total**
Country:						
Canada	**$ 766**	**$ 86**	**$ 852**	$ 802	$ —	$ 802
United States	**1,851**	**458**	**2,309**	706	385	1,091
	$ 2,617	**$ 544**	**$ 3,161**	$ 1,508	$ 385	$ 1,893

For the three and six months ended June 30, 2022, other revenue of $22 million and $46 million was attributed to Canada, respectively (three and six months ended June 30, 2021 – $23 million and $51 million attributed to Canada, respectively).

b. Revenue-related assets

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

As at	**June 30, 2022**	**December 31, 2021**
Petroleum revenue	**$ 528**	$ 455
Other revenue	**8**	10
Total revenue-related assets	**$ 536**	$ 465

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

11. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Unrealized foreign exchange (gain) loss on:				
Long-term debt	$ 73	$ (38)	$ 42	$ (86)
US$ denominated cash and cash equivalents	(14)	(3)	(5)	2
Foreign currency risk management contracts	—	—	(7)	—
Unrealized net (gain) loss on foreign exchange	59	(41)	30	(84)
Realized (gain) loss on foreign exchange	1	—	2	—
Foreign exchange (gain) loss, net	$ 60	$ (41)	$ 32	$ (84)
C$ equivalent of 1 US$				
Beginning of period	1.2508	1.2572	1.2656	1.2755
End of period	1.2872	1.2405	1.2872	1.2405

12. NET FINANCE EXPENSE

	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Interest expense on long-term debt	$ 43	$ 53	$ 90	$ 111
Interest expense on lease liabilities	6	7	12	13
Interest income	(1)	—	(1)	—
Net interest expense	48	60	101	124
Debt extinguishment expense	12	5	12	5
Accretion on provisions	2	2	4	4
Net finance expense	$ 62	$ 67	$ 117	$ 133

For the three and six months ended June 30, 2022, debt extinguishment expense of $12 million was recognized in association with the US$208 million (approximately $268 million) repurchase of the Corporation's 7.125% senior unsecured notes and included a cumulative debt redemption premium of $9 million and associated unamortized deferred debt issue costs of $3 million. Refer to Note 6 for further details.

For the three and six months ended June 30, 2021, debt extinguishment expense of $5 million was recognized in association with the US$100 million (approximately $125 million) redemption of the Corporation's 6.5% senior secured second lien notes and included a cumulative debt redemption premium of $4 million and associated expensing of unamortized deferred debt issue costs of $1 million.

13. INCOME TAX EXPENSE (RECOVERY)

	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Current income tax expense (recovery)	$ —	$ (2)	$ —	$ (2)
Deferred income tax expense (recovery)	92	17	196	(2)
Income tax expense (recovery)	$ 92	$ 15	$ 196	$ (4)

14. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended June 30		Six months ended June 30	
	2022	**2021**	**2022**	**2021**
Cash provided by (used in):				
Trade receivables and other	**$ 100**	$ (57)	**$ (84)**	$ (174)
Inventories	**(14)**	(2)	**(83)**	(36)
Accounts payable and accrued liabilities	**91**	(14)	**126**	92
Interest payable	**29**	47	**(22)**	4
	$ 206	$ (26)	**$ (63)**	$ (114)
Changes in non-cash working capital relating to:				
Operating	**$ 199**	$ 20	**$ (71)**	$ (89)
Investing	**7**	(46)	**8**	(25)
	$ 206	$ (26)	**$ (63)**	$ (114)
Cash and cash equivalents:[(a)]				
Cash	**$ 244**	$ 159	**$ 244**	$ 159
Cash equivalents	**—**	—	**—**	—
	$ 244	$ 159	**$ 244**	$ 159
Cash interest paid	**$ 9**	$ —	**$ 103**	$ 96

a. As at June 30, 2022, $214 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (June 30, 2021 – $6 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$1.2872 (June 30, 2021 – US$1=C$1.2405).

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	(2)	—	—
Payments on leased liabilities	—	(12)	—
Repayment and redemption of long-term debt	—	—	(772)
Debt redemption premium and refinancing costs	—	—	(17)
Other cash and non-cash changes:			
Interest payments on lease liabilities	—	(12)	—
Interest expense on lease liabilities	—	12	—
Unrealized (gain) loss on foreign exchange	—	—	42
Debt redemption premium	—	—	9
Amortization of deferred debt discount and debt issue costs	—	—	2
Balance as at June 30, 2022	**$ 13**	**$ 254**	**$ 2,026**

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

15. NET EARNINGS PER COMMON SHARE

	Three months ended June 30		Six months ended June 30	
	2022	**2021**	**2022**	**2021**
Net earnings	**$ 225**	$ 68	**$ 587**	$ 51
Weighted average common shares outstanding (millions)[a]	**310**	307	**309**	305
Dilutive effect of stock options, RSUs and PSUs (millions)	**4**	4	**5**	5
Weighted average common shares outstanding – diluted (millions)	**314**	311	**314**	310
Net earnings per share, basic	**$ 0.73**	$ 0.22	**$ 1.90**	$ 0.17
Net earnings per share, diluted	**$ 0.72**	$ 0.22	**$ 1.87**	$ 0.17

a. Weighted average common shares outstanding for the three and six months ended June 30, 2022 include 238,773 PSUs vested but not yet released and 120,046 PSUs vested but not yet released, respectively (three and six months ended June 30, 2021 - nil and 272,259 PSUs vested but not yet released, respectively).

16. 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	**June 30, 2022**		**December 31, 2021**	
	Carrying amount	**Fair value**	**Carrying amount**	**Fair value**
Recurring measurements:				
Financial assets				
Commodity risk management contracts	**$ 15**	**$ 15**	$ 3	$ 3
Equity price risk management contracts	**$ 74**	**$ 74**	$ 74	$ 74
Financial liabilities				
Long-term debt (Note 6)	**$ 2,049**	**$ 1,985**	$ 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 June 30, 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 quoted prices in an active market from a third-party independent broker. Management's assumptions rely on external observable market data including forward prices for commodities 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 and WTI fixed price swaps, WTI:condensate fixed differential swaps and total return 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	**June 30, 2022**			**December 31, 2021**		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Gross amount	**$ 89**	**$ —**	**$ 89**	$ 77	$ (7)	$ 70
Amount offset	**—**	**—**	**—**	—	—	—
Net amount	**$ 89**	**$ —**	**$ 89**	$ 77	$ (7)	$ 70
Current portion	**$ 84**	**$ —**	**$ 84**	$ 36	$ (7)	$ 29
Non-current portion	**5**	**—**	**5**	41	—	41
Net amount	**$ 89**	**$ —**	**$ 89**	$ 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 June 30:

As at June 30	**2022**	**2021**
Fair value of contracts, beginning of year	**$ 70**	$ (2)
Fair value of contracts realized	**(48)**	156
Change in fair value of contracts	**67**	(242)
Fair value of contracts, end of period	**$ 89**	$ (88)

c. Commodity risk management:

The Corporation had the following financial commodity risk management contracts relating to condensate and natural gas purchases outstanding as at June 30, 2022:

As at June 30, 2022			
Condensate Purchase Contracts	**Volumes (bbls/d)[(i)]**	**Term**	**Average Price (US$/bbl)**
WTI:Mont Belvieu Fixed Differential	200	Jul 1, 2022 - Dec 31, 2022	$(11.30)
WTI:Mont Belvieu Fixed Differential	7,000	Jan 1, 2023 - Oct 31, 2023	$(11.54)
Natural Gas Purchase Contracts	**Volumes (GJ/d)[(i)]**	**Term**	**Average Price (C$/GJ)**
AECO Fixed Price	5,000	Jul 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.

Incremental to these commodity risk management contracts, the Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months to support marketing asset optimization activities.

The Corporation entered into the following financial commodity risk management contract relating to condensate purchases subsequent to June 30, 2022. As a result, these contracts are not reflected in the Corporation's Interim Consolidated Financial Statements:

Subsequent to June 30, 2022			
Condensate Purchase Contracts	**Volumes (bbls/d)**	**Term**	**Average Price (US$/bbl)**
WTI:Mont Belvieu Fixed Differential	1,500	Jan 1, 2023 - Oct 31, 2023	$(11.03)

The following table summarizes the sensitivity of the earnings (loss) before income tax impact of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place as at June 30, 2022:

Commodity	**Sensitivity Range**	**Increase**	**Decrease**
Condensate purchase price	± 5% in condensate price as a percentage of WTI	**$ 12**	**$ (12)**
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	**$ 1**	**$ (1)**

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

	Three months ended June 30		**Six months ended June 30**	
	2022	**2021**	**2022**	**2021**
Realized loss (gain) on commodity risk management	**$ (1)**	$ 87	**$ (2)**	$ 156
Unrealized loss (gain) on commodity risk management	**(8)**	27	**(12)**	115
Commodity risk management (gain) loss, net	**$ (9)**	$ 114	**$ (14)**	$ 271

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 related to the Corporation's stock-based compensation program. 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 the cash-settled components of 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 any realized asset outstanding at period-end is included in trade receivables and other on the balance sheet.

	Three months ended June 30		Six months ended June 30	
	2022	2021	**2022**	2021
Realized equity price risk management (gain) loss	**$ —**	$ —	**$ (46)**	$ (8)
Unrealized equity price risk management (gain) loss	**(3)**	(18)	**1**	(29)
Equity price risk management (gain) loss	**$ (3)**	$ (18)	**$ (45)**	$ (37)

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 June 30, 2022, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $581 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 June 30, 2022 was $244 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 $244 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.

The Corporation's earliest maturing long-term debt is 4.5 years out, represented by US$992 million 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 $600 million revolving credit facility has no financial maintenance covenant unless drawn in excess of 50%, or $300 million. If drawn in excess of 50%, or $300 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.

17. 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, share buybacks 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 March 7, 2022, the Corporation received approval from the TSX for a 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 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 the Corporation.

The Corporation reached its net debt target of US$1.7 billion during the second quarter of 2022. As a result, the Corporation began allocating approximately 25% of free cash flow generated to share buybacks with the remaining free cash flow applied to ongoing debt reduction which will continue until the Corporation’s net debt balance reaches US$1.2 billion. 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.

The following table summarizes the Corporation's net debt:

As at	Note	June 30, 2022	December 31, 2021
Long-term debt	6	**$ 2,026**	$ 2,477
Current portion of long-term debt	6	**—**	285
Cash and cash equivalents		**(244)**	(361)
Net debt - C$		**$ 1,782**	$ 2,401
Net debt - US$		**$ 1,384**	$ 1,897

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

During the first half of 2022, the Corporation repaid a total of US$604 million (approximately $772 million) of outstanding indebtedness. This reduction in outstanding indebtedness was achieved as follows:

- On January 18, 2022, the redemption of US$225 million (approximately $288 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;

- On April 4, 2022, the redemption of the remaining US$171 million (approximately $216 million) of the Corporation’s outstanding 6.50% senior secured second lien notes due January 2025 at a redemption price of 101.625% plus accrued and unpaid interest; and

- During May and June 2022, the Corporation repurchased and extinguished US$208 million (approximately $268 million) of the Corporation's 7.125% senior unsecured notes due February 2027 at a weighted average price of 103.2% plus accrued and unpaid interest.

Subsequent to June 30, 2022, the Corporation has repurchased a further US$96 million (approximately $124 million) of the Corporation's outstanding 7.125% senior unsecured notes due February 2027 at a weighted average price of 101%.

During the second quarter of 2022, the Corporation began purchasing MEG common shares for cancellation and as at June 30, 2022 the Corporation had purchased for cancellation 4.45 million common shares, returning $94 million to MEG shareholders.

Subsequent to June 30, 2022, the Corporation has purchased for cancellation a further 2.79 million common shares for a total cost of $45 million.

On June 24, 2022, the Corporation amended and restated its Revolving Credit Facility and its letters of credit facility guaranteed by EDC and extended the maturity date of each facility by 2.3 years to October 31, 2026. Total credit available under the two facilities was reduced from $1.3 billion to $1.2 billion and is comprised of $600 million under the Revolving Credit Facility and $600 million under the EDC Facility.

The Revolving Credit Facility retains its modified covenant-lite structure, meaning it continues to contain no financial maintenance covenant unless the Corporation is drawn under the Revolving Credit Facility in excess of 50%. If drawn in excess of 50%, or $300 million, under the Revolving Credit Facility the Corporation is required to maintain a first lien net debt to last twelve month EBITDA ratio of 3.50 or less. The Corporation continues to have no first lien debt outstanding.

The Corporation's earliest maturing long-term debt is approximately 4.5 years out, represented by US$992 million of the 7.125% senior unsecured notes due February 2027. As at June 30, 2022, the Corporation had $596 million of unutilized capacity under the $600 million revolving credit facility and the Corporation had $170 million of unutilized capacity under the $600 million EDC Facility. A letter of credit of $4 million remains outstanding under the revolving credit facility as at June 30, 2022.

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

	Three months ended June 30		**Six months ended June 30**	
($millions)	**2022**	**2021**	**2022**	**2021**
Funds flow from operating activities	**$ 412**	$ 160	**$ 999**	$ 281
Adjustments:				
Impact of cash-settled SBC units subject to equity price risk management	**66**	18	**85**	23
Realized equity price risk management gain	**—**	—	**(46)**	(8)
Payments on onerous contract	**—**	6	**—**	12
Adjusted funds flow	**478**	184	**1,038**	308
Capital expenditures	**(104)**	(71)	**(192)**	(141)
Free cash flow	**$ 374**	$ 113	**$ 846**	$ 167

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.

In the second quarter of 2022, an adjustment was made to the presentation of adjusted funds flow and free cash flow. In April 2020, the Corporation issued cash-settled restricted share units ("RSUs") under its long-term incentive ("LTI") plan when the Corporation's share price was at a historic low of $1.57 per share. Concurrent with the issuance, the Corporation entered into equity price risk management contracts to manage share price volatility in the three-year period following the issuance, effectively eliminating cash flow risk associated with share price appreciation over that time period. The significant increase in the Corporation's share price from April 1, 2020 to June 30, 2022 resulted in the recognition of a significant cash-settled stock-based compensation expense, which was previously included as a component of adjusted funds flow and free cash flow. Since the actual cash impact of the 2020 cash-settled RSUs was hedged through the equity price risk management contracts, there is no cash impact over the term of these RSUs beyond the value at the date of issue of $1.57 per share.

The Corporation's operating performance and cash flow generating ability are not impacted by the April 2020 cash-settled RSUs issued and the associated equity price risk management contracts, therefore the financial statement impacts of the cash-settled stock-based compensation associated with the April 2020 issuance and the equity price risk management contracts have been excluded from Adjusted Funds Flow and Free Cash Flow. All prior periods presented have been adjusted to reflect this change in presentation. The adjustments to prior periods are as follows:

	2022	2021				2020		
($millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Adjusted funds flow, as previously presented	**$ 587**	$ 266	$ 239	$ 166	$ 127	$ 84	$ 26	$ 89
Adjustments:								
Impact of cash-settled SBC units subject to equity price risk management(	**18**	8	4	18	5	4	—	2
Realized equity price risk management gain	**(46)**	—	—	—	(8)	—	—	—
Adjusted funds flow, current presentation	**$ 559**	$ 274	$ 243	$ 184	$ 124	$ 88	$ 26	$ 91
Free cash flow, as previously presented	**$ 499**	$ 160	$ 155	$ 95	$ 57	$ 44	$ (9)	$ 69
Adjustments:								
Impact of cash-settled SBC units subject to equity price risk management	**18**	8	4	18	5	4	—	2
Realized equity price risk management gain	**(46)**	—	—	—	(8)	—	—	—
Free cash flow, current presentation	**$ 471**	$ 168	$ 159	$ 113	$ 54	$ 48	$ (9)	$ 71

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.

18. 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 June 30, 2022:

	2022	2023	2024	2025	2026	Thereafter	Total
Transportation and storage[(i)]	$ 212	$ 431	$ 456	$ 431	$ 410	$ 5,430	$ 7,370
Diluent purchases	93	31	—	—	—	—	124
Other operating commitments	8	16	14	13	13	24	88
Variable office lease costs	2	5	5	5	5	23	45
Capital commitments	23	—	—	—	—	—	23
Commitments	**$ 338**	**$ 483**	**$ 475**	**$ 449**	**$ 428**	**$ 5,477**	**$ 7,650**

(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 7(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.