FIRST QUARTER | 2024

REPORT TO SHAREHOLDERS FOR THE PERIOD ENDED MARCH 31, 2024

Report to Shareholders for the period ended March 31, 2024

(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, bitumen realization net of transportation and storage expense, operating expenses net of power revenue, energy operating costs net of power revenue, non-energy operating costs, energy operating costs, adjusted funds flow, free cash flow and net debt.

MEG Energy Corp. reported first quarter 2024 operational and financial results on May 6, 2024.

"MEG's strong safety, operating, and financial performance in the first quarter of 2024 demonstrate the team's focus on operations excellence," said Darlene Gates, Chief Executive Officer. "Bitumen production averaged approximately 104,000 barrels per day during the quarter, and $217 million of free cash flow supported the repurchase of 4.7 million shares and $142 million of debt redemption. We expect that additional Canadian pipeline capacity from the imminent start up of TMX will narrow heavy oil differentials, reduce differential volatility and improve netbacks on all of MEG's production."

First quarter 2024 highlights include:

- Funds flow from operating activities ("FFO") and adjusted funds flow ("AFF") of $329 million, or $1.19 per share;
- Free cash flow ("FCF") of $217 million, after funding $112 million of capital expenditures;
- Redemption of US$105 million (approximately $142 million) of senior notes;
- Shareholder capital returns totaling $127 million through the repurchase and cancellation of 4.7 million shares at a weighted average price of $26.94 per share;
- Net debt of US$687 million (approximately $930 million) as at March 31, 2024;
- Average bitumen production of 104,088 barrels per day ("bbls/d") at a 2.37 steam-oil ratio ("SOR");
- Bitumen realization after transportation and storage expense of $60.10 per barrel, with the WTI:WCS differential averaging US$19.31 per barrel;
- Operating expenses net of power revenue of $6.37 per barrel. Power revenue offset 68% of energy operating costs, resulting in energy operating costs net of power revenue of $1.19 per barrel and non-energy operating costs of $5.18 per barrel; and
- The Corporation's 2024 operating and capital guidance remains unchanged.

Financial Results

AFF increased to $329 million, or $1.19 per share, in the first quarter of 2024 from $274 million, or $0.94 per share, in the comparable 2023 period driven mainly by a higher cash operating netback and a lower interest expense. Cash operating netback rose $5.67 per barrel in the first quarter of 2024, mainly reflecting a higher bitumen realization after net transportation and storage expense partially offset by higher royalties.

Bitumen realization after net transportation and storage expense rose to $60.10 per barrel in the first quarter of 2024, from $43.40 per barrel in the same period of 2023, primarily driven by narrower WTI:AWB differentials, at both Edmonton and the U.S. Gulf Coast ("USGC"), which increased the blend sales price and lowered diluent expense.

Higher apportionment levels in the first quarter of 2024 reduced sales volumes in the more favorable USGC market. The Corporation sold 48% and 56% of blend sales volumes in the USGC during the first quarters of 2024 and 2023, respectively, with average heavy oil apportionment on the Enbridge mainline system rising to 28% in the first quarter of 2024 from 12% in the comparative 2023 period.

FCF increased to $217 million in first quarter of 2024, from $161 million in the comparable 2023 quarter, primarily reflecting higher AFF.

Capital expenditures of $112 million during the first quarter of 2024 were in line with the same period of 2023 with spending primarily focused on sustaining and maintenance activities in both periods.

Net earnings increased to $98 million in the first quarter of 2024 from $81 million in the same period of 2023 mainly driven by higher AFF partially offset by an unrealized foreign exchange loss on long-term debt, higher depletion and depreciation and increased deferred tax expense.

Operating Results

Bitumen production in the first quarter of 2024 declined 3% to 104,088 bbls/d at a 2.37 SOR from 106,840 bbls/d at a 2.25 SOR in the comparable 2023 period reflecting cold weather impacts, facility maintenance activities and timing of new well start-ups.

Non-energy operating costs averaged $5.18 per barrel of bitumen sales in the first quarter of 2024 representing a 9% increase from the same quarter of 2023 primarily reflecting planned labour cost increases and higher well workover activity.

Energy operating costs net of power revenue decreased to $1.19 per barrel in the first quarter of 2024 from $1.36 per barrel in the comparable 2023 period primarily reflecting a weaker AECO natural gas price partially offset by a decline in the realized power price. Revenue from the sale of excess power generated by the Corporation's cogeneration facilities offset 68% and 76% of energy operating costs in the first quarters of 2024 and 2023, respectively.

Debt Redemption and Share Repurchases

The $217 million of first quarter 2024 FCF, plus available cash, was used to redeem debt and return capital to shareholders. The Corporation redeemed US$105 million (approximately $142 million) of outstanding 7.125% senior unsecured notes at a redemption price of 101.8% and returned $127 million to MEG shareholders through the repurchase and cancellation of 4.7 million shares at a weighted average price of $26.94 per share.

Capital Allocation Strategy

Approximately 50% of FCF was allocated to debt redemption in the first quarter of 2024 with the remainder applied to share repurchases. 100% of FCF will be returned to shareholders when the Corporation reaches its US$600 million net debt target, which is anticipated to occur in the third quarter of 2024. The Corporation exited the first quarter of 2024 with net debt of US$687 million (approximately $930 million).

On March 6, 2024, the Toronto Stock Exchange ("TSX") approved the renewal of the Corporation's normal course issuer bid ("NCIB"). Pursuant to the NCIB, MEG will purchase for cancellation, from time to time, as it considers advisable, up to a maximum of 24,007,526 common shares of the Corporation. The NCIB became effective on March 11, 2024 and will terminate on March 10, 2025 or such earlier time as the NCIB is completed or terminated at the option of MEG.

Adjusted Funds Flow Sensitivity

MEG's production is comprised entirely of crude oil and AFF is highly correlated with crude oil benchmark prices and light-heavy oil differentials. The following table provides an annual sensitivity estimate to the most significant market variables.

Variable	Range	2024 AFF Sensitivity[(1)(2)] - C$mm
WCS Differential (US$/bbl)	+/- US$1.00/bbl	+/- C$47mm
WTI (US$/bbl)	+/- US$1.00/bbl	+/- C$31mm
Bitumen Production (bbls/d)	+/- 1,000 bbls/d	+/- C$16mm
Condensate (US$/bbl)	+/- US$1.00/bbl	+/- C$14mm
Exchange Rate (C$/US$)	+/- $0.01	+/- C$10mm
Non-Energy Opex (C$/bbl)	+/- C$0.25/bbl	+/- C$6mm
AECO Gas[(3)] (C$/GJ)	+/- C$0.50/GJ	+/- C$6mm

(1) Each sensitivity is independent of changes to other variables.

(2) Assumes mid point of 2024 production guidance, US$75.00/bbl WTI, US$16.25/bbl WTI:WCS Edmonton discount, US$1.50/bbl WCS:AWB Edmonton discount, US$7.75/bbl WTI:AWB Gulf Coast discount, C$1.35/US$ F/X rate, condensate purchased at 100% of WTI and one bbl of bitumen per 1.42 bbls of blend sales (1.42 blend ratio).

(3) Assumes 1.4 GJ/bbl of bitumen, 65% of 160 MW of power generation sold externally and a 25.0 GJ/MWh heat rate.

ADVISORY

Forward-Looking Information

This report contains forward-looking information and should be read in conjunction with the "Forward-Looking Information" contained within the Advisory section of this quarterly 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 13 "Non-GAAP and Other Financial Measures" of the Corporation's period ended March 31, 2024 Management's Discussion and Analysis for detailed descriptions of these measures.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three months ended March 31, 2024 was approved by the Corporation's Audit Committee on May 6, 2024. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three months ended March 31, 2024, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2023, the 2023 annual MD&A and the 2023 Annual Information Form ("AIF").

Basis of Presentation

This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards") 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.

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. Please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A for further descriptions of the measures noted below.

Non-GAAP financial measures and ratios include: cash operating netback, blend sales, bitumen realization, net transportation and storage expense, bitumen realization after net transportation and storage expense, operating expenses net of power revenue, energy operating costs net of power revenue, effective royalty rate, and per barrel figures associated with non-GAAP financial measures.

Supplementary financial measures and ratios include: non-energy operating costs, energy operating costs, and per barrel figures associated with supplementary financial measures.

Capital management measures include: adjusted funds flow, free cash flow, and net debt.

MD&A - Table of Contents

1. HIGHLIGHTS

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 operational and financial results are based on bitumen sales volumes:

	2024	2023				2022		
($millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Operational results:								
Bitumen production - bbls/d	**104,088**	109,112	103,726	85,974	106,840	110,805	101,983	67,256
Steam-oil ratio	**2.37**	2.28	2.28	2.25	2.25	2.22	2.39	2.46
Bitumen sales - bbls/d	**105,534**	112,634	101,625	83,531	106,480	113,582	95,759	73,091
Benchmark pricing:								
WTI - US$/bbl	**76.96**	78.32	82.26	73.78	76.13	82.65	91.55	108.41
Differential - WTI:AWB - Edmonton - US$/bbl	**(21.00)**	(23.79)	(14.38)	(17.37)	(27.63)	(29.14)	(22.80)	(14.25)
AWB - Edmonton - US$/bbl	**55.96**	54.53	67.88	56.41	48.50	53.51	68.75	94.16
Differential - WTI:AWB - USGC - US$/bbl	**(8.16)**	(7.43)	(4.94)	(7.62)	(14.87)	(16.35)	(10.15)	(6.15)
AWB - USGC - US$/bbl	**68.80**	70.89	77.32	66.16	61.26	66.30	81.40	102.26
Financial results:								
Bitumen realization after net transportation and storage expense[1] - $/bbl	**60.10**	63.52	84.75	57.64	43.40	54.75	74.75	103.29
Non-energy operating costs[2] - $/bbl	**5.18**	4.64	5.15	5.66	4.77	4.34	4.49	5.65
Energy operating costs net of power revenue[1] - $/bbl	**1.19**	1.46	(0.04)	0.97	1.36	1.49	0.96	7.32
Operating expenses net of power revenue[1] - $/bbl	**6.37**	6.10	5.11	6.63	6.13	5.83	5.45	12.97
Cash operating netback[1] - $/bbl	**39.99**	38.65	58.64	42.38	34.32	43.89	62.63	81.75
General & administrative expense - $/bbl of bitumen production volumes	**2.18**	1.89	1.73	1.85	1.94	1.62	1.72	2.37
Funds flow from operating activities	**329**	358	492	278	348	383	501	412
Per share, diluted	**1.19**	1.27	1.71	0.96	1.19	1.28	1.63	1.31
Adjusted funds flow[3]	**329**	358	492	278	274	401	496	478
Per share, diluted[3]	**1.19**	1.27	1.71	0.96	0.94	1.34	1.61	1.52
Capital expenditures	**112**	104	83	149	113	106	78	104
Free cash flow[3]	**217**	254	409	129	161	295	418	374
Debt repayments - US$	**105**	128	68	40	86	150	262	379
Share repurchases - C$	**127**	219	58	66	103	196	92	94
Revenues	**1,364**	1,444	1,438	1,291	1,480	1,445	1,571	1,571
Net earnings (loss)	**98**	103	249	136	81	159	156	225
Per share, diluted	**0.36**	0.37	0.86	0.47	0.28	0.53	0.51	0.72
Long-term debt, including current portion	**1,015**	1,124	1,323	1,382	1,466	1,581	1,803	2,026
Net debt[3] - US$	**687**	730	885	994	1,020	1,026	1,193	1,384

(1) Non-GAAP financial measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Supplementary financial measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.
(3) Capital management measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.

Financial Results and Capital Resources

The Corporation generated funds flow from operating activities and adjusted funds flow of $329 million during the three months ended March 31, 2024. After $112 million of capital expenditures, the Corporation's remaining free cash flow of $217 million plus available cash was used to redeem debt and return capital to shareholders. During the three months ended March 31, 2024, the Corporation redeemed US$105 million (approximately $142 million) of outstanding 7.125% senior unsecured notes at a redemption price of 101.8% and returned $127 million to MEG shareholders through the repurchase and cancellation of 4.7 million shares at a weighted average price of $26.94 per share.

Average bitumen production volumes during the first quarter of 2024 declined 3% to 104,088 barrels per day at a steam-oil ratio ("SOR") of 2.37, from 106,840 barrels per day at an SOR of 2.25 in the same period of 2023, reflecting cold weather impacts, facility maintenance activities and timing of new well start-ups.

During the three months ended March 31, 2024, funds flow from operating activities and adjusted funds flow were $329 million compared to $348 million and $274 million, respectively, in the same period of 2023. The increase in adjusted funds flow was mainly driven by a higher cash operating netback and lower interest expense due to reduced debt levels. Cash operating netback rose $5.67 per barrel, from the same period of 2023, to $39.99 per barrel in the three months ended March 31, 2024 mainly reflecting a higher bitumen realization after net transportation and storage expense partially offset by higher royalties. Bitumen realization after net transportation and storage expense increased to $60.10 per barrel in the first quarter of 2024 from $43.40 per barrel in the same period of 2023 primarily driven by narrower WTI:AWB differentials, at both Edmonton and the USGC, which increased the blend sales price and lowered diluent expense.

Capital expenditures remained relatively stable at $112 million in the three months ended March 31, 2024 compared to $113 million in the same period of 2023, with spending primarily focused on sustaining and maintenance activities.

Free cash flow increased to $217 million in the first quarter of 2024 from $161 million in the same period of 2023.

Net earnings increased to $98 million during the three months ended March 31, 2024 from $81 million in the comparable 2023 quarter reflecting higher adjusted funds flow partially offset by an unrealized foreign exchange loss on long-term debt and higher depletion and depreciation expense.

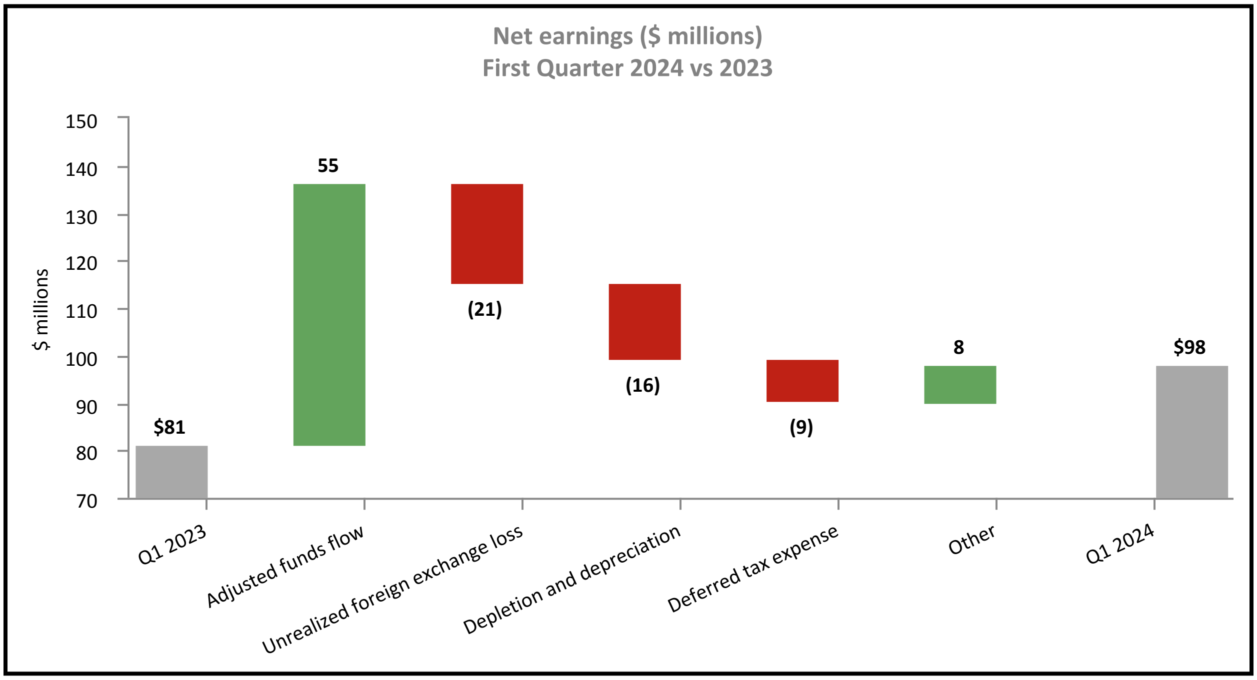
Cash and cash equivalents were $85 million at March 31, 2024. The Corporation exited the first quarter of 2024 with total debt and net debt of $1,015 million and $930 million (US$687 million), respectively.

2. SUSTAINABILITY AND PATHWAYS UPDATE

MEG, along with its Pathways Alliance peers, continues to progress pre-work on the proposed foundational carbon capture and storage ("CCS") project, which will transport CO_2 via pipeline from multiple oil sands facilities to be stored safely and permanently underground in the Cold Lake region of Alberta. Regulatory applications were filed to the Alberta Energy Regulator on March 22, 2024, seeking approvals for the CO_2 transportation network and storage hub. The Pathways Alliance continues to advance detailed evaluations of the proposed carbon storage hub and is working to obtain a carbon sequestration agreement from the Alberta Government. In addition, the Pathways Alliance continues to advance engineering work, environmental field programs to minimize the project's environmental disturbance, and consultations with Indigenous and local communities along the proposed CO_2 transportation and storage network corridor. The Pathways Alliance continues to work collaboratively with both the federal and Alberta Governments on the necessary policy and co-financing frameworks required to move the project forward. The federal government has proposed an investment tax credit ("ITC") for CCS projects for all sectors across Canada and expects implementing legislation for the CCS ITC by the end of the year 2024. In addition, the Alberta Government announced an Alberta Carbon Capture Incentive Program which aims to help hard-to-abate industries by providing a grant of 12% for new eligible CCS capital costs. The Pathways Alliance is evaluating these proposals.

Additional information regarding the Corporation's ESG actions, including the Corporation's 2023 ESG Report, is available in the "Sustainability" section of the Corporation's website at www.megenergy.com. The Corporation's ESG Report and contents of MEG's website are expressly not incorporated by reference in this MD&A.

3. NET EARNINGS



Net earnings increased to $98 million during the three months ended March 31, 2024 from $81 million in the same period of 2023 primarily driven by higher adjusted funds flow partially offset by an unrealized foreign exchange loss on long-term debt, higher depletion and depreciation and increased deferred tax expense.

4. REVENUES

	Three months ended March 31	
($millions)	**2024**	**2023**
Sales from:		
Production	**$ 1,153**	$ 1,043
Purchased product[(1)]	**313**	427
Petroleum revenue	**$ 1,466**	$ 1,470
Royalties	**(128)**	(31)
Petroleum revenue, net of royalties	**$ 1,338**	$ 1,439
Power revenue	**$ 25**	$ 40
Transportation revenue	**1**	1
Power and transportation revenue	**$ 26**	$ 41
Revenues	**$ 1,364**	$ 1,480

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

During the three months ended March 31, 2024, petroleum revenue, net of royalties decreased to $1.3 billion from $1.4 billion in the same period of 2023. Increased royalties and lower sales from purchased product were partially offset by narrower WTI:AWB differentials at Edmonton and the USGC.

Revenues include the sale of third-party products related to marketing asset optimization activities. The associated purchase of third-party products is recognized within "Purchased product" expense. These transactions are mainly undertaken to recover fixed costs related to transportation and storage contracts. 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 physical transactions or through financial price risk management.

5. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended March 31	
	2024	**2023**
Bitumen production – bbls/d	**104,088**	106,840
Steam-oil ratio (SOR)	**2.37**	2.25

Bitumen Production

Bitumen production decreased approximately 3% in the three months ended March 31, 2024, compared to the same period of 2023, reflecting cold weather impacts, facility maintenance activities and timing of new well start-ups.

Steam-Oil Ratio ("SOR")

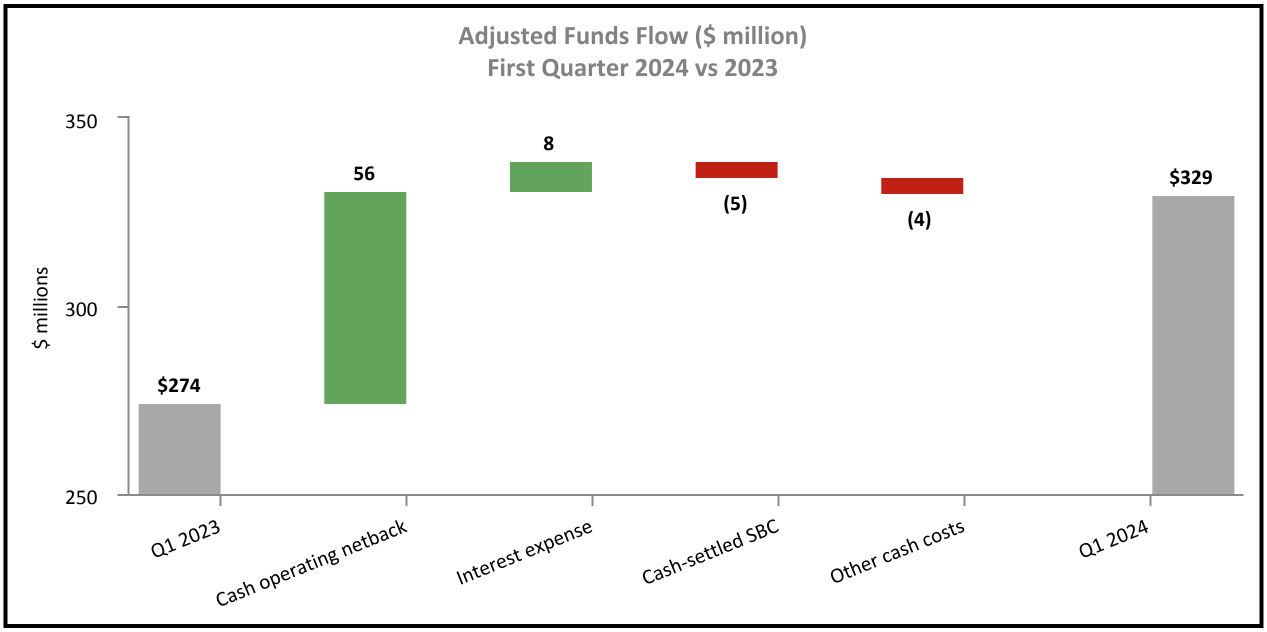
The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is SOR, which is an efficiency indicator that measures the amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR increased approximately 5%, from the same period of 2023, to 2.37, in the three months ended March 31, 2024 primarily due to planned timing of injecting steam in new well starts.

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 operations. 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 establishes a clearer link between cash flows and the cash operating netback.

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

	Three months ended March 31	
($millions, except as indicated)	**2024**	**2023**
Funds flow from operating activities	**$ 329**	$ 348
Adjustments:		
Impact of cash-settled SBC units subject to equity price risk management	**—**	13
Realized equity price risk management gain	**—**	(87)
Adjusted funds flow	**$ 329**	$ 274
Adjusted funds flow per share - diluted	**$ 1.19**	$ 0.94



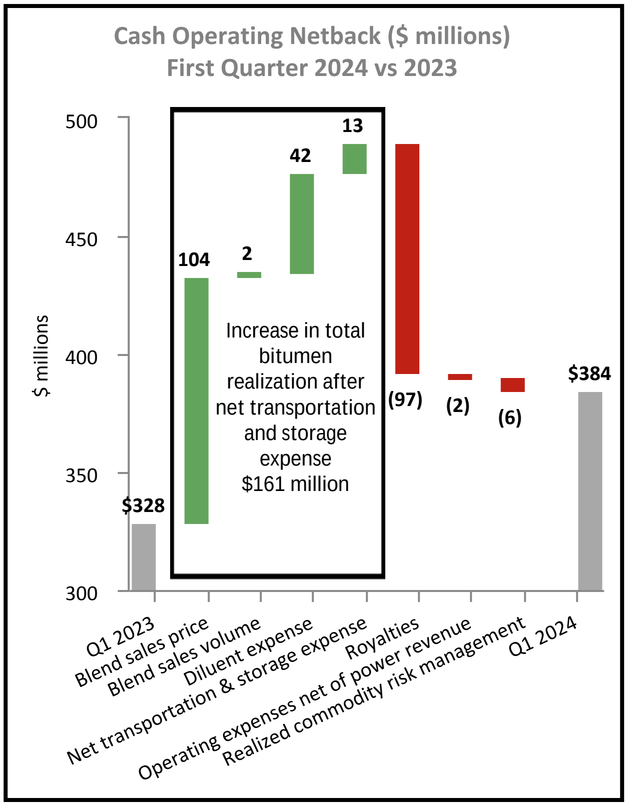
Adjusted funds flow increased in the three months ended March 31, 2024, compared to the same period of 2023, driven mainly by a higher cash operating netback and a lower interest expense due to reduced debt levels.

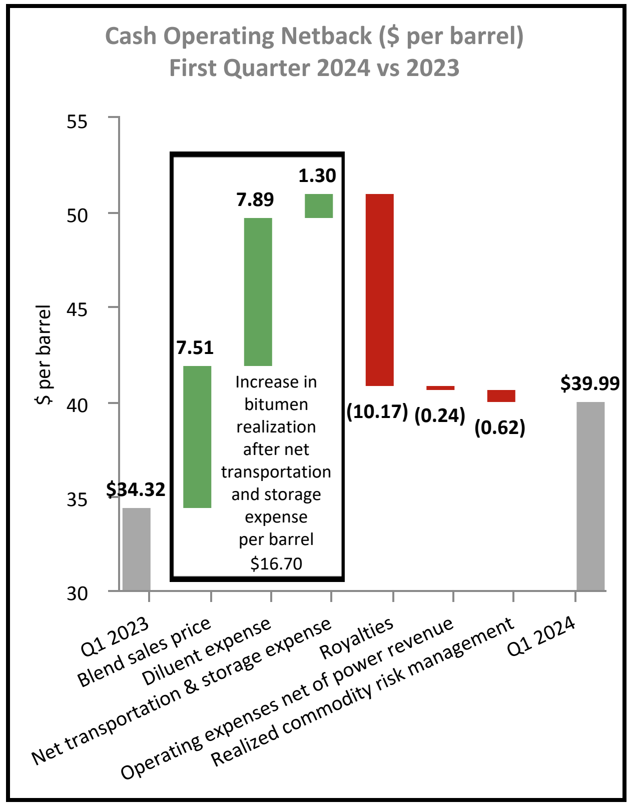
CASH OPERATING NETBACK

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

	Three months ended March 31			
	2024		**2023**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Sales from production	**$ 1,153**		$ 1,043	
Sales from purchased product[1]	**313**		427	
Petroleum revenue	**$ 1,466**		$ 1,470	
Purchased product[1]	**(304)**		(414)	
Blend sales[2][3]	**$ 1,162**	**$ 83.58**	$ 1,056	$ 76.07
Diluent expense	**(456)**	**(10.00)**	(498)	(17.89)
Bitumen realization[3]	**$ 706**	**$ 73.58**	$ 558	$ 58.18
Net transportation and storage expense[3][4]	**(129)**	**(13.48)**	(142)	(14.78)
Bitumen realization after net transportation and storage expense[3]	**$ 577**	**$ 60.10**	$ 416	$ 43.40
Royalties	**(128)**	**(13.35)**	(31)	(3.18)
Operating expenses net of power revenue[3]	**(61)**	**(6.37)**	(59)	(6.13)
Realized gain (loss) on commodity risk management	**(4)**	**(0.39)**	2	0.23
Cash operating netback[3]	**$ 384**	**$ 39.99**	$ 328	$ 34.32
Bitumen sales volumes - bbls/d		**105,534**		106,480

(1) *Sales and purchases of oil products mainly 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 13 "Non-GAAP and Other Financial Measures" of this MD&A.*
(4) *Net transportation and storage expense includes costs associated with moving and storing AWB to optimize the timing of delivery.*





During the three months ended March 31, 2024, cash operating netback, on a total and per barrel basis, increased compared to the same period of 2023 mainly reflecting a higher bitumen realization after net transportation and storage expense partially offset by higher royalties.

Bitumen Realization after Net Transportation and Storage Expense

Bitumen realization after net transportation and storage expense reflects the effective realized bitumen price at Christina Lake and is calculated as blend sales less diluent expense and net transportation and storage expense. 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. Diluent expense is impacted by Canadian and U.S. benchmark pricing, the amount of diluent required, which is impacted by pipeline specification seasonality, the cost of transporting diluent to the production site from both Edmonton and USGC markets, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar. Diluent volumes are typically held in inventory for 30 to 60 days and approximately 20,000 barrels per day of diluent is sourced from the Mont Belvieu, Texas market with the remainder from Edmonton. The cost of purchased diluent is partially offset by the sales of such diluent in blend volumes.

The Corporation's marketing strategy focuses on maximizing bitumen realization after net transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access. Bitumen realization after net transportation and storage expense per barrel fluctuates primarily based on the WTI benchmark price and the WTI:AWB differential.

	Three months ended March 31			
	2024		2023	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	$ 1,153		$ 1,043	
Sales from purchased product[1]	313		427	
Petroleum revenue	$ 1,466		$ 1,470	
Purchased product[1]	(304)		(414)	
Blend sales[2][3]	$ 1,162	$ 83.58	$ 1,056	$ 76.07
Diluent expense	(456)	(10.00)	(498)	(17.89)
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Net transportation and storage expense[3]	(129)	(13.48)	(142)	(14.78)
Bitumen realization after net transportation and storage expense	$ 577	$ 60.10	$ 416	$ 43.40
Bitumen sales volumes - bbls/d		105,534		106,480

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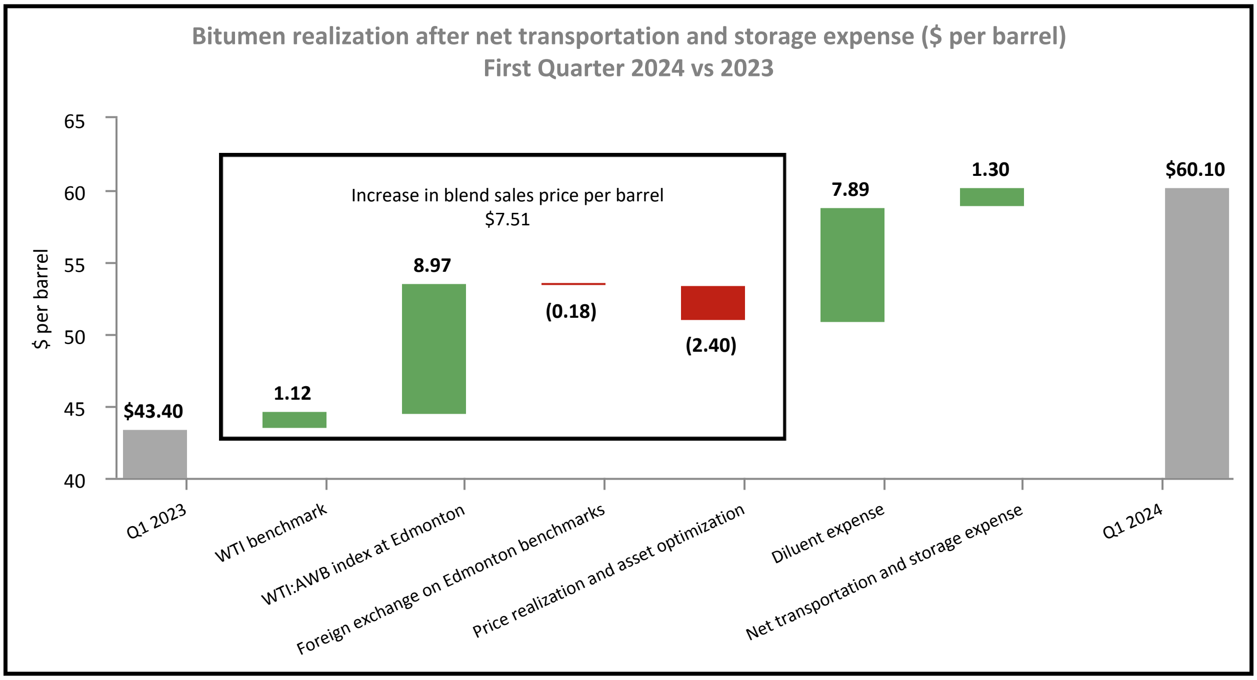


Bitumen realization after net transportation and storage expense increased 38%, to $60.10 per barrel, in the three months ended March 31, 2024, from $43.40 per barrel in the same period of 2023, primarily driven by narrower WTI:AWB differentials, at both Edmonton and the USGC, which increased the blend sales price and lowered diluent expense.

The decreased diluent expense, on a total and per barrel basis, also reflects a lower average condensate price, relative to WTI. As a result, the Corporation recovered 79% of diluent costs through blend sales during the three months ended March 31, 2024 compared to 66% in the same period of 2023.

These factors were partially offset by higher apportionment levels in the first quarter of 2024 which reduced sales volumes in the more favorable USGC market. The Corporation sold 48% of its blend sales volumes in the USGC during the three months ended March 31, 2024 compared to 56% during the same period of 2023. Average heavy oil apportionment on the Enbridge mainline system rose to 28% from 12% in the first quarters of 2024 and 2023, respectively.

	Three months ended March 31			
	2024		2023	
($millions, except as indicated)		$/bbl		$/bbl
Transportation and storage expense	**$ (130)**	**$ (13.55)**	$ (143)	$ (14.88)
Transportation revenue	**1**	**0.07**	1	0.10
Net transportation and storage expense	**$ (129)**	**$ (13.48)**	$ (142)	$ (14.78)
Bitumen sales volumes - bbls/d		**105,534**		106,480

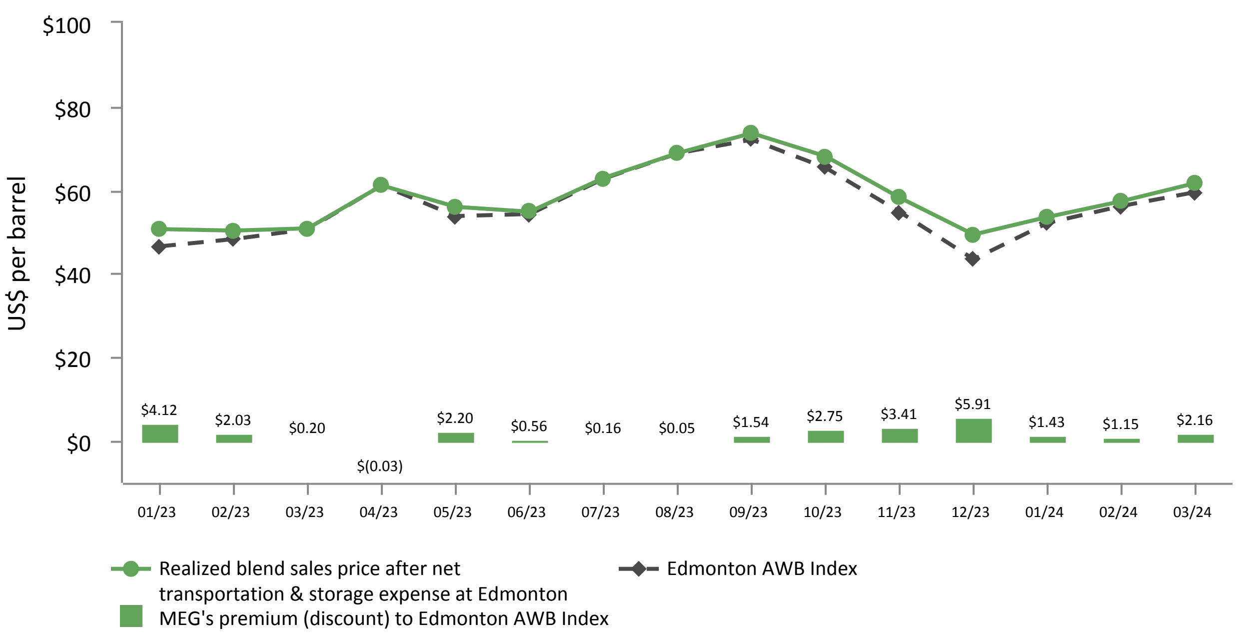
Net transportation and storage expense in the three months ended March 31, 2024, on a total and per barrel basis, declined relative to the same period of 2023 primarily reflecting lower volumes transported to the USGC, as a result of higher pipeline apportionment, partially offset by higher per barrel pipeline tolls.

When expressed on a US$ per barrel of blend sales basis, net transportation and storage expense was US$6.90 during the three months ended March 31, 2024 compared to US$7.55 during 2023.

The Corporation partially mitigated the cost of transportation and storage assets through the purchase and sale of non-proprietary product. These asset optimization activities added $9 million, or $0.67 per barrel, to blend sales in the three months ended March 31, 2024 compared to $13 million, or $0.93 per barrel, in the same period of 2023.

Marketing transportation and storage assets are strategically utilized to access diverse global markets and enhance realized prices. The premium (discount) on the realized blend sales price, net of transportation and storage, at Edmonton relative to the Edmonton AWB index, provides an indication of value derived through transportation and storage commitments.

Premium (discount) on realized blend sales price after net transportation and storage expense, at Edmonton relative to AWB index price at Edmonton



In the first quarters of 2024 and 2023, the Corporation's ability to access the USGC increased the realized blend sales price relative to the Edmonton AWB index by US$1.54 per barrel and US$2.25 per barrel, respectively.

Royalties

The Oil Sands Royalty Regulation, 2009, establishes royalty rates that are linked to the WTI price measured in Canadian dollars. The royalty payable is calculated on bitumen production and applies price-sensitive royalty rates to gross or net revenue depending on whether the project's status is pre or post payout. "Payout" is generally defined as the point in time when a project has generated enough net revenue to recover costs and provide a designated return allowance. When a project reaches payout, its cumulative revenue equals or exceeds cumulative costs.

The pre-payout royalty is based on the project’s gross revenue multiplied by a gross revenue royalty rate. Gross revenues are comprised of bitumen realization after transportation and storage expense attributed to the project. The gross revenue royalty rate starts at 1% and increases for every dollar the WTI oil price in Canadian dollars is priced above $55 per barrel, to a maximum of 9% when the Canadian dollar WTI price is $120 per barrel or higher.

The post-payout royalty is the greater of (i) the gross revenue royalty; or (ii) the net revenue royalty. Net revenues are comprised of bitumen realization after transportation and storage expense attributed to the project and allowed operating and capital costs. The net revenue royalty rate starts at 25% and increases for every dollar the Canadian dollar WTI oil price is above $55 per barrel to a maximum of 40% when the Canadian dollar WTI price is $120 per barrel or higher.

	Three months ended March 31	
($millions)	**2024**	**2023**
Bitumen realization	**$ 706**	$ 558
Transportation and storage expense	**(130)**	(143)
Transportation revenue	**1**	1
Bitumen realization after net transportation and storage expense	**$ 577**	$ 416
Royalties	**$ 128**	$ 31
Effective royalty rate(1)(2)	**22.2 %**	7.5 %

(1) Effective royalty rate is calculated as royalties divided by bitumen realization after net transportation and storage expense.
(2) Non-GAAP financial measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.

The Corporation’s Christina Lake operation reached payout status in the second quarter of 2023. Therefore, royalties were recognized on a net revenue basis in the three months ended March 31, 2024, resulting in increased royalty expense and a higher effective royalty rate relative to the same period in 2023.

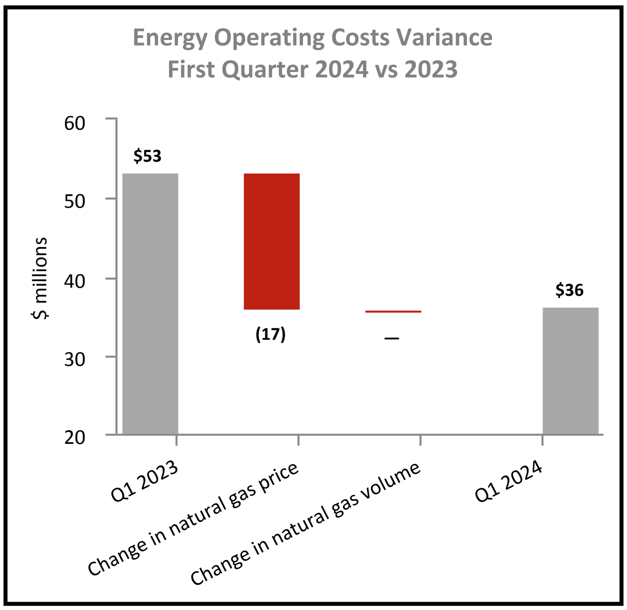
Operating Expenses net of Power Revenue

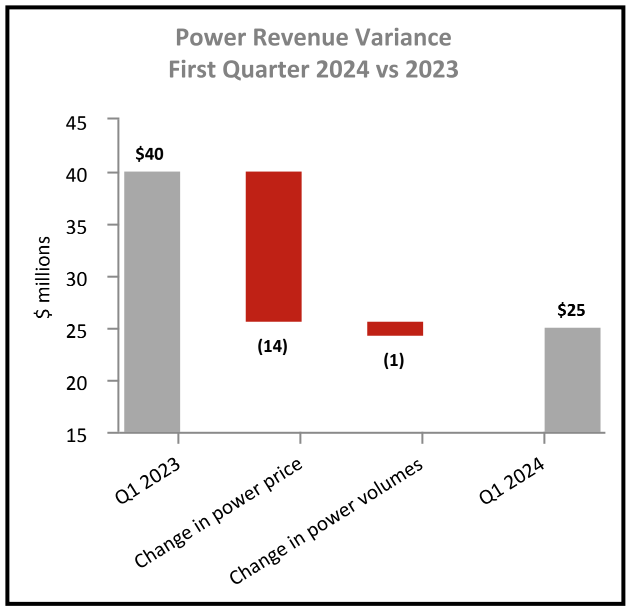
Operating expenses net of power revenue are comprised of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-oriented operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate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

	Three months ended March 31			
	2024		2023	
($millions, except as indicated)		$/bbl		$/bbl
Non-energy operating costs[1]	**$ (50)**	**$ (5.18)**	$ (46)	$ (4.77)
Energy operating costs[1]	**(36)**	**(3.74)**	(53)	(5.57)
Operating expenses	**(86)**	**(8.92)**	(99)	(10.34)
Power revenue	**25**	**2.55**	40	4.21
Operating expenses net of power revenue[2]	**$ (61)**	**$ (6.37)**	$ (59)	$ (6.13)
Energy operating costs net of power revenue[2]	**$ (11)**	**$ (1.19)**	$ (13)	$ (1.36)
Average delivered natural gas price (C$/mcf)		**$ 3.03**		$ 4.54
Average realized power sales price (C$/Mwh)		**$ 102.53**		$ 162.90

(1) Supplementary financial measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.
(2) Non-GAAP financial measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.

Non-energy operating costs in the three months ended March 31, 2024, on a total and per barrel basis, increased compared to the same period of 2023 primarily reflecting planned labour cost increases and higher well workover activity.





First quarter of 2024 per barrel energy operating costs net of power revenue decreased to $1.19 from $1.36 in the same period of 2023 as lower natural gas costs more than offset reduced power revenue.

Lower energy operating costs in the three months ended March 31, 2024 primarily reflect a weaker AECO natural gas price relative to the same period of 2023. Natural gas volumes were similar in both quarters.

First quarter of 2024 power revenue decreased from the comparable 2023 quarter primarily reflecting a 37% decline in the realized power price. Power sales volumes were similar in both quarters.

Capital Expenditures

Capital expenditures of $112 million during the first quarter of 2024 were in line with $113 million during the same period of 2023 with spending primarily focused on sustaining and maintenance activities.

6. OUTLOOK

The Corporation's 2024 operating and capital guidance released on November 27, 2023 remains unchanged.

Summary of 2024 Guidance	
Bitumen production - annual average	102,000 to 108,000 bbls/d
Capital expenditures	$550 million
Non-energy operating costs	$5.10 to $5.40 per bbl
G&A expense	$1.75 to $1.95 per bbl

7. BUSINESS ENVIRONMENT

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

AVERAGE BENCHMARK COMMODITY PRICES	**2024**		**2023**			**2022**		
	Q1	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Crude oil prices								
Brent (US$/bbl)	**81.85**	81.61	85.95	78.01	82.21	88.59	97.69	111.57
WTI (US$/bbl)	**76.96**	78.32	82.26	73.78	76.13	82.65	91.55	108.41
Differential – WTI:WCS – Edmonton (US$/bbl)	**(19.31)**	(21.89)	(12.91)	(15.16)	(24.88)	(25.89)	(19.86)	(12.80)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(21.00)**	(23.79)	(14.38)	(17.37)	(27.63)	(29.14)	(22.80)	(14.25)
AWB – Edmonton (US$/bbl)	**55.96**	54.53	67.88	56.41	48.50	53.51	68.75	94.16
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(8.16)**	(7.43)	(4.94)	(7.62)	(14.87)	(16.35)	(10.15)	(6.15)
AWB – U.S. Gulf Coast (US$/bbl)	**68.80**	70.89	77.32	66.16	61.26	66.30	81.40	102.26
Enbridge Mainline heavy crude apportionment %	**28**	21	1	1	12	5	3	0
Condensate prices								
Condensate at Edmonton (C$/bbl)	**98.18**	103.90	104.62	97.19	107.91	113.17	113.97	138.39
Condensate at Edmonton as a % of WTI	**94.6**	97.4	94.8	98.1	104.8	100.9	95.3	100.0
Condensate at Mont Belvieu, Texas (US$/bbl)	**64.52**	62.28	64.90	60.54	68.13	64.57	72.25	90.98
Condensate at Mont Belvieu, Texas as a % of WTI	**83.8**	79.5	78.9	82.1	89.5	78.1	78.9	83.9
Natural gas prices								
AECO (C$/mcf)	**2.72**	2.51	2.83	2.67	3.51	5.57	4.54	7.89
Electric power prices								
Alberta power pool (C$/MWh)	**98.87**	81.76	151.18	159.87	141.63	213.66	221.90	122.49
Foreign exchange rates								
C$ equivalent of 1 US$ – average	**1.3488**	1.3618	1.3410	1.3430	1.3520	1.3577	1.3059	1.2766
C$ equivalent of 1 US$ – period end	**1.3533**	1.3205	1.3537	1.3238	1.3528	1.3534	1.3700	1.2872

Crude Oil Prices

Brent is the primary world price benchmark for global light sweet crude oil. 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 production.

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 pipelines leaving the Edmonton market. The WCS benchmark at Edmonton reflects heavy oil prices at Hardisty, Alberta.

The Corporation sells AWB, which is similar to WCS but generally prices at a discount reflecting quality differences and heavy sour oil supply/demand fundamentals. AWB is also delivered to the USGC where it is typically sold at a discount to WTI reflecting supply/demand fundamentals for heavy sour oil in that region.

While the WTI price was similar in the first quarters of 2024 and 2023, WCS and AWB differentials improved year over year reflecting strong global demand for heavy crude and incremental demand in preparation for the Trans Mountain Expansion ("TMX") Pipeline linefill and start-up.

Condensate Prices

In order to facilitate pipeline transportation, the Corporation uses condensate as diluent for blending with its bitumen. The price of condensate generally correlates with the price of WTI and is sourced 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 from the USGC at Mont Belvieu, Texas benchmark pricing. Condensate pricing at Edmonton and the USGC, as a percentage of WTI, fell in the first quarter of 2024 compared to the same period of 2023 primarily due to lower international demand. In particular, USGC condensate pricing as a percentage of WTI has remained below historical levels due to lower demand stemming from a global reduction in manufacturing output and the associated curtailment in petrochemical feedstock requirements.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation and is used as fuel to generate steam for the thermal production process and to create steam and electricity from cogeneration facilities. The Corporation purchases natural gas in Alberta based on the AECO natural gas index price. The average AECO natural gas price decreased 23% in the first quarter of 2024, relative to the comparable 2023 period, primarily due to record natural gas production in North America more than offsetting demand growth along with improved international supply leading to significantly reduced global pricing.

Electric Power Prices

Electric power prices impact the revenue that the Corporation receives on the sale of surplus power from the Christina Lake Project cogeneration facilities. The Alberta power pool price weakened 30% in the first quarter of 2024, compared to the same period of 2023, reflecting increasing penetration of renewables and substantially lower natural gas prices.

8. OTHER OPERATING RESULTS

General and Administrative

	Three months ended March 31	
($millions, except as indicated)	**2024**	**2023**
General and administrative	**$ 20**	$ 18
General and administrative expense per barrel of production	**$ 2.18**	$ 1.94
Bitumen production - bbls/d	**104,088**	106,840

G&A expense during the three months ended March 31, 2024 increased compared to the same period of 2023 primarily due to higher costs associated with increased staff and salaries.

Depletion and Depreciation

	Three months ended March 31	
($millions, except as indicated)	**2024**	**2023**
Depletion and depreciation expense	**$ 159**	$ 143
Depletion and depreciation expense per barrel of production	**$ 16.79**	$ 14.86
Bitumen production - bbls/d	**104,088**	106,840

During the three months ended March 31, 2024, depletion and depreciation expense rose by $16 million, compared to the same period of 2023, mainly reflecting the impact of higher estimated future development costs on the per barrel depletion and depreciation rate.

Stock-based Compensation

	Three months ended March 31	
($millions)	**2024**	**2023**
Cash-settled expense	**$ 11**	$ 18
Equity-settled expense	**7**	8
Equity price risk management gain	**—**	(9)
Stock-based compensation expense	**$ 18**	$ 17

The decrease in cash-settled stock-based compensation expense was mainly the result of fewer cash-settled units outstanding in the first quarter of 2024 compared to the same period of 2023.

The equity price risk management gain in the first quarter of 2023 reflected the increase in the Corporation's common share price during that period. As at March 31, 2023, all equity price risk management contracts were fully realized.

Foreign Exchange Gain (Loss), Net

	Three months ended March 31	
($millions)	**2024**	**2023**
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ (28)**	$ —
US$ denominated cash and cash equivalents	**6**	(1)
Unrealized net gain (loss) on foreign exchange	**(22)**	(1)
Realized gain (loss) on foreign exchange	**(1)**	—
Foreign exchange gain (loss), net	**$ (23)**	$ (1)

C$ equivalent of 1 US$		
Beginning of period	**1.3205**	1.3534
End of period	**1.3533**	1.3528

Foreign exchange gains (losses) reflect fluctuations in the U.S. dollar to Canadian dollar exchange rate and are primarily driven by the Corporation's U.S. dollar denominated long-term debt.

During the three months ended March 31, 2024, the Canadian dollar weakened relative to the U.S. dollar by 2% resulting in an unrealized foreign exchange loss of $22 million. During the comparative 2023 period the exchange rate was largely unchanged.

Net Finance Expense

	Three months ended March 31	
($millions)	**2024**	**2023**
Interest expense on long-term debt	**$ 19**	$ 26
Interest expense on lease liabilities	**6**	6
Credit facility fees	**3**	3
Interest income	**(3)**	(2)
Net interest expense	**25**	33
Debt extinguishment expense	**7**	4
Accretion on provisions	**3**	3
Net finance expense	**$ 35**	$ 40
Average effective interest rate	**6.2%**	6.5%

Interest expense on long-term debt decreased during the three months ended March 31, 2024, compared to the same period of 2023, primarily reflecting the US$341 million (approximately $461 million) of debt repaid since April 1, 2023.

For the three months ended March 31, 2024, debt extinguishment expense of $7 million was recognized, including $3 million associated with the redemption of US$105 million (approximately $142 million) of the Corporation's 7.125% senior unsecured notes and $4 million associated with the prepayment option on forecast note redemptions. Refer to Note 9 of the interim consolidated financial statements for further details.

Income Tax

	Three months ended March 31	
($millions)	**2024**	**2023**
Earnings before income taxes	**$ 137**	$ 110
Effective tax rate	**28 %**	26 %
Income tax expense	**$ 39**	$ 29

As at March 31, 2024, the Corporation had approximately $4.4 billion of available Canadian tax pools, including $3.0 billion of non-capital losses and $0.2 billion of capital losses, and recognized a deferred income tax liability of $214 million.

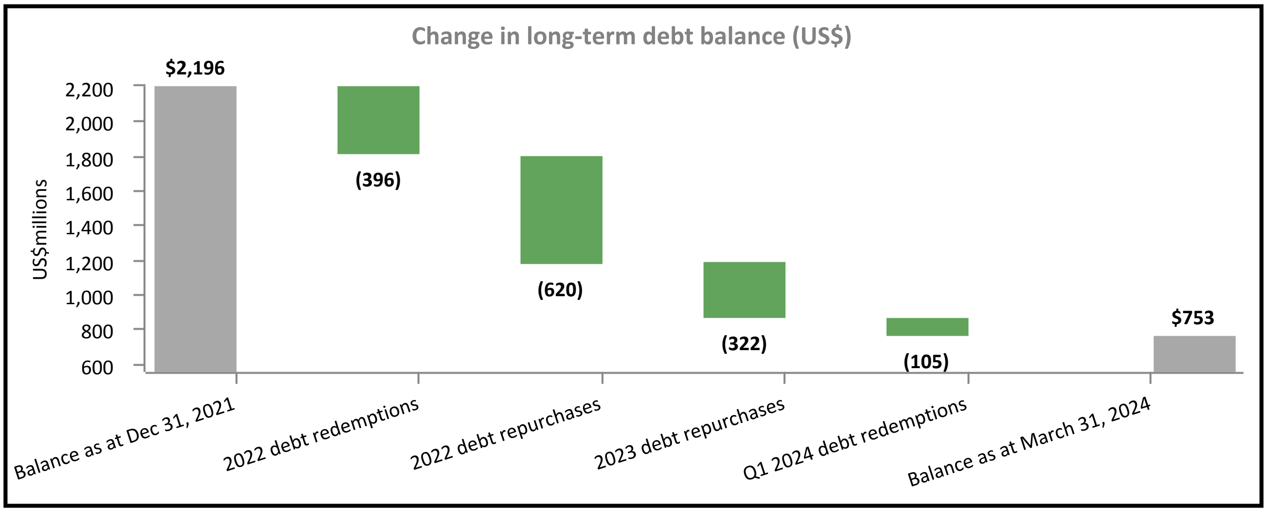
The effective tax rate for the three months ended March 31, 2024 differed from the Canadian statutory rate of 23% primarily due to the tax effect of foreign exchange losses on the Corporation's U.S. dollar denominated long-term debt.

9. LIQUIDITY AND CAPITAL RESOURCES

($millions)	**March 31, 2024**	**December 31, 2023**
Unsecured:		
7.125% senior unsecured notes (March 31, 2024 - US$153.2 million; due 2027; December 31, 2023 - US$258.2 million)	**$ 207**	$ 341
5.875% senior unsecured notes (March 31, 2024 - US$600 million; due 2029; December 31, 2023 - US$600 million)	**812**	792
Debt redemption premium	**4**	—
Unamortized deferred debt discount and debt issue costs	**(8)**	(9)
Current and long-term debt	**1,015**	1,124
Cash and cash equivalents	**(85)**	(160)
Net debt - C$(1)	**$ 930**	$ 964
Net debt - US$(1)	**$ 687**	$ 730

(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 20 of the interim consolidated financial statements.

The Corporation redeemed, and repurchased and extinguished, its long-term debt as noted below:



The Corporation's cash and cash equivalents decreased to $85 million at March 31, 2024 from $160 million at December 31, 2023. Refer to the "Cash Flow Summary" section for further details.

The Corporation's net debt decreased to US$687 million at March 31, 2024 from US$730 million at December 31, 2023.

In 2022, the Corporation initiated the allocation of approximately 25% of free cash flow to share repurchases with the remainder applied to debt repayment. When net debt declined to US$1.2 billion, free cash flow allocated to share repurchases was raised to approximately 50% with the remainder applied to debt repayment. This free cash flow allocation strategy will remain in place until net debt reaches US$600 million, which is anticipated to occur in the third quarter of 2024.

On March 6, 2024, the Toronto Stock Exchange ("TSX") approved the renewal of the Corporation's normal course issuer bid ("NCIB"). Pursuant to the NCIB, MEG will purchase for cancellation, from time to time, as it considers advisable, up to a maximum of 24,007,526 common shares of the Corporation. The NCIB became effective on March 11, 2024 and will terminate on March 10, 2025 or such earlier time as the NCIB is completed or terminated at the option of MEG.

The Corporation has $1.2 billion of available credit, comprised of $600 million under a revolving credit facility and $600 million under a letter of credit facility guaranteed by Export Development Canada ("EDC Facility"). Letters of credit under the EDC Facility do not consume capacity of the revolving credit facility. The revolving credit facility and the EDC Facility have maturity dates of October 31, 2026 and are secured by substantially all the assets of the Corporation.

Commodity market volatility is managed through the Corporation's various financial frameworks. Credit exposure is reduced by targeting sales to primarily investment grade customers. The US$153 million of 7.125% senior unsecured notes due February 2027 represents the earliest long-term debt maturity. Additionally, the modified covenant-lite $600 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $300 million, or 50%. If drawn in excess of $300 million, or 50%, 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 revolving credit facility plus other debt that is secured on a *pari passu* basis with the revolving credit facility, less cash-on-hand. None of the outstanding long-term debt contains financial maintenance covenants or is secured on a *pari passu* basis with the revolving credit facility.

At March 31, 2024, the Corporation had $600 million of unutilized capacity under the revolving credit facility and with $296 million of issued letters of credit, had $304 million of unutilized capacity under the $600 million EDC Facility. 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 current capital resources and the ability to manage cash flow and working capital levels allows the Corporation to meet current and future obligations, make scheduled principal and interest payments, and fund 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 asset development are dependent on factors discussed in the "RISK FACTORS" section of this MD&A.

Cash Flow Summary

	Three months ended March 31	
($millions)	**2024**	**2023**
Net cash provided by (used in):		
Operating activities	**$ 317**	$ 237
Investing activities	**(119)**	(111)
Financing activities	**(279)**	(232)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**6**	(1)
Change in cash and cash equivalents	**$ (75)**	$ (107)

Cash Flow – Operating Activities

Net cash provided by operating activities during the three months ended March 31, 2024 increased $80 million, compared to the same period of 2023, primarily due to a higher blend sales price partially offset by increased royalties and less funds used for working capital requirements.

Cash Flow – Investing Activities

Net cash used in investing activities increased $8 million during the three months ended March 31, 2024, compared to the same period of 2023, reflecting increased funds used for working capital requirements.

Cash Flow – Financing Activities

Net cash used in financing activities increased $47 million in the three months ended March 31, 2024, from the same period of 2023, reflecting more free cash flow available for debt repayment and share repurchases.

10. RISK MANAGEMENT

Commodity Price Risk Management

The Corporation periodically enters into financial commodity risk management contracts to protect and increase the predictability of cash flow, manage commodity input costs and to support marketing asset optimization activities pursuant to Board approved policies. Financial commodity risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss).

Realized gains or losses on financial commodity risk management contracts are the result of 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, and the offset to the realized risk management gain (loss) recognized on contract settlements.

	Three months ended March 31	
($millions)	**2024**	**2023**
Realized commodity risk management gain (loss)	**$ (4)**	$ 2
Unrealized commodity risk management gain (loss)	**4**	—
Commodity risk management gain (loss)	**$ —**	$ 2

The Corporation had the following financial commodity risk management contracts relating to natural gas purchases outstanding at March 31, 2024:

Natural Gas Purchase Contracts	Volumes (GJ/d)	Term	Average Price (C$/GJ)
AECO Fixed Price	30,000	Apr 1, 2024 - Dec 31, 2024	$4.11

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

The Corporation periodically enters 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 contracts are recognized in the consolidated statement of earnings and comprehensive income and in cash operating netback as the contracts are realized.

The Corporation had the following physical commodity risk management contracts relating to natural gas purchases outstanding as at March 31, 2024:

Natural Gas Purchase Contracts	Volumes (GJ/d)	Term	Average Price (C$/GJ)
AECO Fixed Price	5,000	Apr 1, 2024 - Dec 31, 2024	$2.00

Equity Price Risk Management

Equity price risk is the risk that changes in the Corporation’s own share price impacts earnings and cash flows. Earnings and funds flow from operating activities are impacted when outstanding cash-settled instruments, issued under the stock-based compensation plans, are revalued each period based on the Corporation’s share price and 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. Equity price risk management (gain) loss is recognized in stock-based compensation expense on the statement of earnings. The unrealized asset (liability) is included in risk management on the balance sheet and any realized asset outstanding at period-end is included in accrued revenues and accounts receivable on the balance sheet. In March 2020, the Corporation entered financial equity price risk management contracts to manage exposure on cash-settled RSUs and PSUs vesting between April 1, 2021 and March 31, 2023.

	Three months ended March 31	
($millions)	**2024**	**2023[1]**
Unrealized equity price risk management (gain) loss	**$ —**	$ 78
Realized equity price risk management (gain) loss	**—**	(87)
Equity price risk management (gain) loss	**$ —**	$ (9)

(1) As at March 31, 2023, all outstanding financial equity price risk management contracts were fully realized.

11. SHARES OUTSTANDING

At March 31, 2024, the Corporation had the following share capital instruments outstanding or exercisable:

(thousands)	**Units**
Common shares:	
Outstanding at December 31, 2023	274,642
Issued upon exercise of stock options	153
Issued upon vesting and release of equity-settled RSUs and PSUs	2,311
Repurchased for cancellation	(4,730)
Common shares outstanding at March 31, 2024	**272,376**
Convertible securities:	
Stock options[1]	**2**
Equity-settled RSUs and PSUs	**2,294**

(1) All outstanding stock options were exercisable at March 31, 2024.

In the three months ended March 31, 2024, the Corporation repurchased for cancellation 4.7 million common shares under its NCIB program at a weighted average price of $26.94 per share for a total cost of $127 million.

At May 3, 2024, the Corporation had 271.5 million common shares outstanding, 2 thousand stock options outstanding and exercisable and 2.3 million equity-settled RSUs and PSUs outstanding.

12. 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 obligations at March 31, 2024. These estimates 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)	2024	2025	2026	2027	2028	Thereafter	Total
Commitments:							
Transportation and storage[1]	$ 366	$ 491	$ 490	$ 493	$ 498	$ 5,169	$ 7,507
Diluent purchases[2]	231	45	5	—	—	—	281
Other operating commitments	14	18	18	9	9	59	127
Variable office lease costs	3	5	5	4	4	13	34
Capital commitments	45	—	—	—	—	—	45
Total Commitments	659	559	518	506	511	5,241	7,994
Other Obligations:							
Lease liabilities	28	39	37	37	37	413	591
Long-term debt[3]	—	—	—	207	—	812	1,019
Interest on long-term debt[3]	47	63	62	50	48	6	276
Decommissioning obligation[4]	3	9	9	9	9	829	868
Total Commitments and Obligations	**$ 737**	**$ 670**	**$ 626**	**$ 809**	**$ 605**	**$ 7,301**	**$ 10,748**

(1) This represents transportation and storage commitments from 2024 to 2048, including the estimated TMX commitment which is not yet in service. Excludes finance leases recognized on the consolidated balance sheet.

(2) The associated transportation commitment is included in transportation and storage.

(3) 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 March 31, 2024.

(4) 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 and believes that any liabilities that may arise pertaining to such matters would not have a material impact on its financial position.

13. 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.

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

	Three months ended March 31	
($millions)	**2024**	**2023**
Funds flow from operating activities	**$ 329**	$ 348
Adjustments:		
Impact of cash-settled SBC units subject to equity price risk management	**—**	13
Realized equity price risk management gain	**—**	(87)
Adjusted funds flow	**329**	274
Capital expenditures	**(112)**	(113)
Free cash flow	**$ 217**	$ 161

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	**March 31, 2024**	**December 31, 2023**
Long-term debt	**$ 1,015**	$ 1,124
Cash and cash equivalents	**(85)**	(160)
Net debt - C$	**$ 930**	$ 964
Net debt - US$	**$ 687**	$ 730

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 volumes.

Revenues is an IFRS measure in the Corporation's consolidated statement of earnings and comprehensive income 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 March 31	
($millions)	**2024**	**2023**
Revenues	**$ 1,364**	$ 1,480
Diluent expense	**(456)**	(498)
Transportation and storage expense	**(130)**	(143)
Purchased product	**(304)**	(414)
Operating expenses	**(86)**	(99)
Realized gain (loss) on commodity risk management	**(4)**	2
Cash operating netback	**$ 384**	$ 328

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 is 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 and comprehensive income, 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 March 31			
	2024		**2023**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Revenues	**$ 1,364**		$ 1,480	
Power and transportation revenue	**(26)**		(41)	
Royalties	**128**		31	
Petroleum revenue	**1,466**		1,470	
Purchased product	**(304)**		(414)	
Blend sales	**1,162**	**$ 83.58**	1,056	$ 76.07
Diluent expense	**(456)**	**(10.00)**	(498)	(17.89)
Bitumen realization	**$ 706**	**$ 73.58**	$ 558	$ 58.18

Net Transportation and Storage Expense

Net transportation and storage expense 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.

Transportation and storage expense is an IFRS measure in the Corporation's consolidated statements of earnings and comprehensive income.

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

	Three months ended March 31							
	2024				2023			
($millions, except as indicated)				**$/bbl**				**$/bbl**
Transportation and storage expense	**$**	**(130)**	**$**	**(13.55)**	$	(143)	$	(14.88)
Power and transportation revenue	**$**	**26**			$	41		
Less power revenue		**(25)**				(40)		
Transportation revenue	**$**	**1**	**$**	**0.07**	$	1	$	0.10
Net transportation and storage expense	**$**	**(129)**	**$**	**(13.48)**	$	(142)	$	(14.78)

Bitumen Realization after Net Transportation and Storage Expense

Bitumen realization after net transportation and storage expense 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 net transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access.

	Three months ended March 31							
	2024				2023			
($millions, except as indicated)				**$/bbl**				**$/bbl**
Bitumen realization[1]	**$**	**706**	**$**	**73.58**	$	558	$	58.18
Net transportation and storage expense[1]		**(129)**		**(13.48)**		(142)		(14.78)
Bitumen realization after net transportation and storage expense	**$**	**577**	**$**	**60.10**	$	416	$	43.40

(1) Non-GAAP financial measure as defined in this section.

Operating Expenses net of Power Revenue and Energy Operating Costs net of Power Revenue

Operating expenses net of power revenue and Energy operating costs net of power revenue are both non-GAAP financial measures, or ratios when expressed on a per barrel basis. 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. Per barrel amounts are based on bitumen sales volumes.

Operating expenses net of power revenue 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.

Energy operating costs net of power revenue is used to measure the performance of the Corporation's cogeneration facilities to offset energy operating costs.

Non-energy operating costs and energy operating costs are supplementary financial measures as they represent portions of operating expenses. Non-energy operating costs comprise 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 and comprehensive income. Power and transportation revenue is an IFRS measure in the Corporation's consolidated statement of earnings and comprehensive income which is the most directly comparable primary financial statement measure to power revenue. A reconciliation from power and transportation revenue to power revenue has been provided below.

	Three months ended March 31			
	2024		2023	
($millions, except as indicated)		$/bbl		$/bbl
Non-energy operating costs	**$ (50)**	**$ (5.18)**	$ (46)	$ (4.77)
Energy operating costs	**(36)**	**(3.74)**	(53)	(5.57)
Operating expenses	**$ (86)**	**$ (8.92)**	$ (99)	$ (10.34)
Power and transportation revenue	**$ 26**		$ 41	
Less transportation revenue	**(1)**		(1)	
Power revenue	**$ 25**	**$ 2.55**	$ 40	$ 4.21
Operating expenses net of power revenue	**$ (61)**	**$ (6.37)**	$ (59)	$ (6.13)
Energy operating costs net of power revenue	**$ (11)**	**$ (1.19)**	$ (13)	$ (1.36)

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 enables 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 after net transportation and storage expense (non-GAAP measure reconciled above).

	Three months ended March 31	
($millions)	2024	2023
Bitumen realization	**$ 706**	$ 558
Transportation and storage expense	**(130)**	(143)
Transportation revenue	**1**	1
Bitumen realization after net transportation and storage expense	**$ 577**	$ 416
Royalties	**$ 128**	$ 31
Effective royalty rate	**22.2 %**	7.5 %

14. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting policies and estimates are those estimates having a significant impact on the 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 material accounting policies and the significant accounting estimates, assumptions and judgments can be found in the Corporation's annual audited consolidated financial statements for the year ended December 31, 2023.

15. 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.sedarplus.ca.

16. 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.

17. 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.

18. 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
AUC	Alberta Utilities Commission
AWB	Access Western Blend
$ or C$	Canadian dollars
CEPA	Canadian Environmental Protection Act, 1999
DSU	Deferred Share Units
EDC	Export Development Canada
eMSAGP	enhanced Modified Steam And Gas Push
ERM	Enterprise Risk Management
ESG	Environment, Social and Governance
FSP	Flanagan South and Seaway Pipeline
G&A	General and administrative
GAAP	Generally Accepted Accounting Principles
GGPPA	Greenhouse Gas Pollution Pricing Act
GHG	Greenhouse Gas
IFRS	International Financial Reporting Standards
LTI	Long-term incentive
NCIB	Normal Course Issuer Bid
MD&A	Management's Discussion and Analysis
OPEC	Organization of Petroleum Exporting Countries
OPEC+	Organization of Petroleum Exporting Countries plus an informal association of other oil producing countries
PSU	Performance Share Units
RSU	Restricted Share Units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam-oil ratio
SBC	Stock-based compensation
TIER	Technology Innovation and Emissions Reduction Regulation
TMX	Trans Mountain Expansion
U.S.	United States
US$	United States dollars
USGC	United States Gulf Coast
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

19. 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; the Corporation’s 2024 outlook, including its expectations regarding 2024 annual average production, capital expenditures, non-energy operating costs, and general and administrative costs; the Corporation’s expectation of allocating 50% of free cash flow to share repurchases with the remaining cash flow applied to ongoing debt repayment until it reaches a net debt floor of US$600 million, which is expected to occur in the third quarter of 2024 at current oil prices; the Corporation’s marketing strategy and marketing asset optimization strategy; the Corporation’s 2030 GHG emissions (Scope 1 and Scope 2) reduction target of 0.63 megatonnes per year and its expectations regarding the Pathways Alliance projects and government support of these projects, including the goal of the Pathways Alliance of obtaining a carbon sequestration agreement from the Alberta government by mid-2024; 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 belief that 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; the Corporation’s belief that any liabilities that may accrue to the Corporation arising out of various legal claims associated with the normal course of operations would not have a material impact on the Corporation’s financial position; and the Corporation’s statements regarding its 2024 commodity risk management contracts.

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; 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 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 potential for a temporary suspension of operations impacted by public health crises; actions taken by OPEC+ in relation to supply management; the impact of the Russian invasion of Ukraine and associated sanctions on commodity prices and the impact of other international and regional relations and other geopolitical tensions and events; 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; the impact of a cybersecurity incident; 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.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about MEG's prospective results of operations including, without limitation, the Corporation's capital expenditures, non-energy operating costs and general and administrative costs, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on FOFI. MEG's actual results, performance or achievement could differ materially from those expressed in, or implied by, these FOFI, or if any of them do so, what benefits MEG will derive therefrom. MEG has included the FOFI in order to provide readers with a more complete perspective on MEG's future operations and such information may not be appropriate for other purposes. MEG disclaims any intention or obligation to update or revise any FOFI statements, whether as a result of new information, future events or otherwise, except as required by law.

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.sedarplus.ca.

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.

20. 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.sedarplus.ca.

21. QUARTERLY SUMMARIES

	2024	2023				2022		
Unaudited	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**98**	103	249	136	81	159	156	225
Per share, diluted	**0.36**	0.37	0.86	0.47	0.28	0.53	0.51	0.72
Funds flow from operating activities	**329**	358	492	278	348	383	501	412
Per share, diluted	**1.19**	1.27	1.71	0.96	1.19	1.28	1.63	1.31
Adjusted funds flow(1)	**329**	358	492	278	274	401	496	478
Per share, diluted(1)	**1.19**	1.27	1.71	0.96	0.94	1.34	1.61	1.52
Capital expenditures	**112**	104	83	149	113	106	78	104
Free cash flow(1)	**217**	254	409	129	161	295	418	374
Working capital	**226**	278	495	231	219	289	395	437
Net debt - C$(1)	**930**	964	1,198	1,316	1,381	1,389	1,634	1,782
Net debt - US$(1)	**687**	730	885	994	1,020	1,026	1,193	1,384
Shareholders' equity	**4,511**	4,527	4,641	4,441	4,370	4,383	4,418	4,339
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**76.96**	78.32	82.26	73.78	76.13	82.65	91.55	108.41
Differential – WTI:WCS – Edmonton (US$/bbl)	**(19.31)**	(21.89)	(12.91)	(15.16)	(24.88)	(25.89)	(19.86)	(12.80)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(21.00)**	(23.79)	(14.38)	(17.37)	(27.63)	(29.14)	(22.80)	(14.25)
AWB – Edmonton (US$/bbl)	**55.96**	54.53	67.88	56.41	48.50	53.51	68.75	94.16
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(8.16)**	(7.43)	(4.94)	(7.62)	(14.87)	(16.35)	(10.15)	(6.15)
AWB – U.S. Gulf Coast (US$/bbl)	**68.80**	70.89	77.32	66.16	61.26	66.30	81.40	102.26
Enbridge Mainline heavy apportionment	**28 %**	21 %	1 %	1 %	12 %	5 %	3 %	0 %
C$ equivalent of 1US$ – average	**1.3488**	1.3618	1.3410	1.3430	1.3520	1.3577	1.3059	1.2766
Natural gas – AECO ($/mcf)	**2.72**	2.51	2.83	2.67	3.51	5.57	4.54	7.89
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**152,844**	158,850	140,002	119,187	154,197	160,163	131,327	105,517
Diluent usage – bbls/d	**(47,310)**	(46,216)	(38,377)	(35,656)	(47,717)	(46,581)	(35,568)	(32,426)
Bitumen sales – bbls/d	**105,534**	112,634	101,625	83,531	106,480	113,582	95,759	73,091
Bitumen production – bbls/d	**104,088**	109,112	103,726	85,974	106,840	110,805	101,983	67,256
Steam-oil ratio (SOR)	**2.37**	2.28	2.28	2.25	2.25	2.22	2.39	2.46
Blend sales(2)	**83.58**	87.33	101.53	87.81	76.07	83.28	99.96	128.20
Diluent expense	**(10.00)**	(9.58)	(0.06)	(10.27)	(17.89)	(14.12)	(9.63)	(5.51)
Bitumen realization(2)	**73.58**	77.75	101.47	77.54	58.18	69.16	90.33	122.69
Net transportation and storage expense(2)	**(13.48)**	(14.23)	(16.72)	(19.90)	(14.78)	(14.41)	(15.58)	(19.40)
Bitumen realization after net transportation and storage expense(2)	**60.10**	63.52	84.75	57.64	43.40	54.75	74.75	103.29
Royalties	**(13.35)**	(17.92)	(19.45)	(7.69)	(3.18)	(5.15)	(7.47)	(8.67)
Non-energy operating costs(3)	**(5.18)**	(4.64)	(5.15)	(5.66)	(4.77)	(4.34)	(4.49)	(5.65)
Energy operating costs(3)	**(3.74)**	(3.25)	(3.42)	(3.92)	(5.57)	(6.71)	(6.12)	(10.40)
Power revenue	**2.55**	1.79	3.46	2.95	4.21	5.22	5.16	3.08
Realized gain (loss) on commodity risk management	**(0.39)**	(0.85)	(1.55)	(0.94)	0.23	0.12	0.80	0.10
Cash operating netback(2)	**39.99**	38.65	58.64	42.38	34.32	43.89	62.63	81.75
Revenues	**1,364**	1,444	1,438	1,291	1,480	1,445	1,571	1,571
Power sales price (C$/MWh)	**102.53**	81.66	156.04	150.19	162.90	219.81	217.25	117.94
Power sales (MW/h)	**113**	108	97	71	118	116	98	82
Average cost of diluent ($/bbl of diluent)	**105.89**	110.65	101.68	111.85	116.01	117.72	125.91	140.61
Average cost of diluent as a % of WTI	**102 %**	104 %	92 %	113 %	113 %	105 %	105 %	102 %
Depletion and depreciation rate per bbl of production	**16.79**	19.01	15.28	14.88	14.86	15.84	14.30	14.35
General and administrative expense per bbl of production	**2.18**	1.89	1.73	1.85	1.94	1.62	1.72	2.37
COMMON SHARES								
Shares outstanding, end of period (000)	**272,376**	274,642	283,290	285,566	288,614	291,081	301,649	307,271
Common share price ($) - close (end of period)	**31.10**	23.67	26.43	21.00	21.71	18.85	15.46	17.82

(1) *Capital management measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.*
(2) *Non-GAAP financial measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Supplementary financial measure - please refer to section 13 "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 ranged from a quarterly average of US$73.78/bbl to US$108.41/bbl;
- variability in WTI:AWB differential at Edmonton which ranged from a quarterly average of US$14.25/bbl to US$29.14/bbl;
- 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;
- transition of royalty status for the Christina Lake project from pre-payout to post-payout in the second quarter of 2023, which impacts the Crown royalty rate and resulting royalty expense;
- timing of capital projects;
- inflationary pressure;
- pipeline 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 cost estimates;
- changes in the Corporation's share price and the resulting impact on stock-based compensation and financial equity price risk management contracts; and
- planned turnaround, unplanned outages and other maintenance activities affecting production.

22. ANNUAL SUMMARIES

	2023	2022	2021	2020	2019	2018[1]	2017[1]
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	**569**	902	283	(357)	(62)	(119)	166
Per share, diluted	**1.98**	2.92	0.91	(1.18)	(0.21)	(0.40)	0.57
Funds flow from operating activities	**1,476**	1,882	753	239	741	169	343
Per share, diluted	**5.13**	6.09	2.42	0.78	2.46	0.56	1.18
Adjusted funds flow[2]	**1,402**	1,934	826	281	724	175	371
Per share, diluted[2]	**4.87**	6.26	2.65	0.92	2.41	0.58	1.28
Capital expenditures	**449**	376	331	149	198	622	508
Free cash flow[2]	**953**	1,558	495	132	526	(447)	(137)
Working capital	**278**	289	150	55	123	290	313
Net debt - C$[2]	**964**	1,389	2,401	2,798	2,917	3,422	4,205
Net debt - US$[2]	**730**	1,026	1,897	2,194	2,250	2,508	3,359
Shareholders' equity	**4,527**	4,383	3,808	3,506	3,853	3,886	3,964
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/bbl)	**77.62**	94.23	67.91	39.40	57.03	64.77	50.95
Differential – WTI:WCS – Edmonton (US$/bbl)	**(18.71)**	(18.27)	(13.04)	(12.60)	(12.76)	(26.31)	(11.98)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(20.79)**	(20.64)	(14.71)	(14.32)	(14.95)	(29.99)	(14.09)
AWB – Edmonton (US$/bbl)	**56.83**	73.59	53.20	25.08	42.08	34.78	36.86
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(8.72)**	(9.62)	(4.60)	(4.77)	(1.77)	(6.68)	(7.61)
AWB - U.S. Gulf Coast (US$/bbl)	**68.90**	84.61	63.31	34.63	55.26	58.09	43.34
Enbridge Mainline heavy apportionment	**9 %**	5 %	42 %	24 %	43 %	41 %	20 %
C$ equivalent of 1US$ – average	**1.3495**	1.3016	1.2536	1.3413	1.3269	1.2962	1.2980
Natural gas – AECO ($/mcf)	**2.88**	5.79	3.95	2.43	1.92	1.62	2.29
OPERATIONAL **($/bbl unless specified)**							
Blend sales, net of purchased product – bbls/d	**143,063**	135,873	131,659	118,347	134,223	125,368	115,766
Diluent usage – bbls/d	**(41,977)**	(40,182)	(39,521)	(35,626)	(40,637)	(38,317)	(35,766)
Bitumen sales – bbls/d	**101,086**	95,691	92,138	82,721	93,586	87,051	80,000
Bitumen production – bbls/d	**101,425**	95,338	93,733	82,441	93,082	87,731	80,774
Steam-oil ratio (SOR)	**2.27**	2.36	2.43	2.32	2.22	2.19	2.31
Blend sales[3]	**87.94**	102.02	72.20	37.65	61.29	53.47	51.39
Diluent expense	**(9.30)**	(10.07)	(9.73)	(10.42)	(8.08)	(16.78)	(9.36)
Net transportation and storage expense[3]	**(16.18)**	(15.29)	(10.93)	(12.92)	(10.84)	(8.42)	(6.89)
Bitumen realization after net transportation & storage expense[3]	**62.46**	76.66	51.54	14.31	42.37	28.27	35.14
Curtailment	**—**	—	—	0.06	(0.37)	—	—
Royalties	**(12.37)**	(6.43)	(2.25)	(0.31)	(1.30)	(1.20)	(0.77)
Non-energy operating costs[4]	**(5.01)**	(4.73)	(4.24)	(4.38)	(4.61)	(4.62)	(4.62)
Energy operating costs[4]	**(4.03)**	(7.29)	(4.94)	(3.29)	(2.38)	(1.98)	(2.98)
Power revenue	**3.08**	4.11	2.58	1.49	1.75	1.51	0.76
Realized gain (loss) on commodity risk management	**(0.77)**	0.29	(9.32)	11.34	(3.31)	(4.37)	(0.39)
Cash operating netback[3]	**43.36**	62.61	33.37	19.22	32.15	17.61	27.14
Revenues	**5,653**	6,118	4,321	2,292	3,931	2,733	2,474
Power sales price (C$/MWh)	**136.50**	162.33	90.10	47.81	56.70	47.87	21.49
Power sales (MW/h)	**98**	104	115	108	121	114	118
Average cost of diluent ($/bbl of diluent)	**110.34**	126.00	94.88	61.86	79.89	91.60	72.32
Average cost of diluent as a % of WTI	**105 %**	103 %	111 %	117 %	106 %	109 %	109 %
Depletion and depreciation rate per bbl of production	**16.10**	14.57	13.15	13.60	20.90	14.12	16.13
General and administrative expense per bbl of production	**1.86**	1.78	1.65	1.62	1.99	2.58	2.94
COMMON SHARES							
Shares outstanding, end of period (000)	**274,642**	291,081	306,865	302,681	299,508	296,841	294,104
Common share price ($) - close (end of period)	**23.67**	18.85	11.70	4.45	7.39	7.71	5.14

(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 13 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Non-GAAP financial measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.*
(4) *Supplementary financial measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.*

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

As at	Note	March 31, 2024	December 31, 2023
Assets			
Current assets			
Cash and cash equivalents	17	**$ 85**	$ 160
Accrued revenue and accounts receivable	3	**454**	465
Inventories	4	**237**	235
Risk management	19	**—**	2
		776	862
Non-current assets			
Property, plant and equipment	5	**5,611**	5,683
Exploration and evaluation assets	6	**128**	128
Other assets	7	**227**	225
Total assets		**$ 6,742**	$ 6,898
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	8	**$ 485**	$ 499
Interest payable		**12**	31
Current portion of provisions and other liabilities	10	**35**	30
Risk management	19	**18**	24
		550	584
Non-current liabilities			
Long-term debt	9	**1,015**	1,124
Provisions and other liabilities	10	**452**	486
Deferred income tax liability		**214**	177
Total liabilities		**2,231**	2,371
Shareholders’ equity			
Share capital	11	**4,786**	4,845
Contributed surplus		**164**	180
Deficit		**(477)**	(531)
Accumulated other comprehensive income		**38**	33
Total shareholders’ equity		**4,511**	4,527
Total liabilities and shareholders’ equity		**$ 6,742**	$ 6,898

Commitments and contingencies (Note 21)
The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

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

Three Months Ended March 31	Note	2024	2023
Revenues			
Petroleum revenue, net of royalties	13	**$ 1,338**	$ 1,439
Power and transportation revenue	13	**26**	41
Revenues		**1,364**	1,480
Expenses			
Diluent expense		**456**	498
Transportation and storage expense		**130**	143
Operating expenses		**86**	99
Purchased product		**304**	414
Depletion and depreciation	5, 7	**159**	143
General and administrative		**20**	18
Stock-based compensation	12	**18**	17
Net finance expense	15	**35**	40
Other income		**(4)**	(1)
Commodity risk management loss (gain), net	19	**—**	(2)
Foreign exchange (gain) loss, net	14	**23**	1
Earnings before income taxes		**137**	110
Income tax expense	16	**39**	29
Net earnings		**98**	81
Other comprehensive income, net of tax			
Items that may be reclassified to profit or loss:			
Foreign currency translation adjustment		**5**	—
Comprehensive income		**$ 103**	$ 81
Net earnings per common share			
Basic	18	**$ 0.36**	$ 0.28
Diluted	18	**$ 0.36**	$ 0.28

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, 2023	**$ 4,845**	**$ 180**	**$ (531)**	**$ 33**	**$ 4,527**
Stock-based compensation	**—**	**7**	**—**	**—**	**7**
Stock options exercised	**1**	**—**	**—**	**—**	**1**
RSUs and PSUs vested and released	**23**	**(23)**	**—**	**—**	**—**
Repurchase of shares for cancellation	**(83)**	**—**	**(44)**	**—**	**(127)**
Comprehensive income	**—**	**—**	**98**	**5**	**103**
Balance as at March 31, 2024	**$ 4,786**	**$ 164**	**$ (477)**	**$ 38**	**$ 4,511**
Balance as at December 31, 2022	$ 5,164	$ 169	$ (988)	$ 38	$ 4,383
Stock-based compensation	—	8	—	—	8
Stock options exercised	1	—	—	—	1
RSUs vested and released	13	(13)	—	—	—
Repurchase of shares for cancellation	(87)	—	(16)	—	(103)
Comprehensive income	—	—	81	—	81
Balance as at March 31, 2023	$ 5,091	$ 164	$ (923)	$ 38	$ 4,370

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

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

Three Months Ended March 31	Note	2024	2023
Cash provided by (used in):			
Operating activities			
Net earnings		**$ 98**	$ 81
Adjustments for:			
Deferred income tax expense		**38**	29
Depletion and depreciation	5, 7	**159**	143
Stock-based compensation	12	**7**	86
Unrealized loss on foreign exchange	14	**22**	1
Unrealized net gain on commodity risk management	19	**(4)**	—
Debt extinguishment expense	15	**7**	4
Accretion on provisions	15	**3**	3
Other		**(2)**	1
Decommissioning expenditures	10	**(2)**	—
Net change in long-term incentive compensation liability		**3**	—
Funds flow from operating activities		**329**	348
Net change in non-cash working capital items	17	**(12)**	(111)
Net cash provided by (used in) by operating activities		**317**	237
Investing activities			
Capital expenditures	5	**(112)**	(113)
Net change in non-cash working capital items	17	**(7)**	2
Net cash provided by (used in) investing activities		**(119)**	(111)
Financing activities			
Repurchase and redemption of long-term debt	9	**(142)**	(117)
Debt redemption premium	9	**(4)**	(3)
Repurchase of shares	11	**(127)**	(103)
Issue of shares, net of issue costs		**1**	—
Receipts on leased assets	17	**1**	—
Payments on leased liabilities	17	**(4)**	(4)
Net change in non-cash working capital items	17	**(4)**	(5)
Net cash provided by (used in) financing activities		**(279)**	(232)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**6**	(1)
Change in cash and cash equivalents		**(75)**	(107)
Cash and cash equivalents, beginning of year		**160**	192
Cash and cash equivalents, end of period		**$ 85**	$ 85

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, 2023. 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 as issued by the International Accounting Standards Board ("IFRS Accounting Standards"), 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, 2023. These interim consolidated financial statements should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2023.

These interim consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation's functional currency and were approved by the Corporation's Audit Committee on May 6, 2024.

3. ACCRUED REVENUE AND ACCOUNTS RECEIVABLE

As at	March 31, 2024	December 31, 2023
Accrued revenue	$ 424	$ 428
Accounts receivable	10	21
Deposits and advances	18	14
Current portion of sublease receivable	2	2
	$ 454	$ 465

4. INVENTORIES

As at	March 31, 2024	December 31, 2023
Bitumen blend	$ 195	$ 196
Diluent	25	23
Material and supplies	17	16
	$ 237	$ 235

5. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Right-of-use assets	Corporate assets	Total
Cost				
Balance as at December 31, 2023	$ 10,396	$ 308	$ 79	$ 10,783
Additions	112	2	—	114
Change in decommissioning provision	(27)	—	—	(27)
Balance as at March 31, 2024	**$ 10,481**	**$ 310**	**$ 79**	**$ 10,870**

Accumulated depletion and depreciation				
Balance as at December 31, 2023	$ 4,954	$ 85	$ 61	$ 5,100
Depletion and depreciation	153	5	1	159
Balance as at March 31, 2024	**$ 5,107**	**$ 90**	**$ 62**	**$ 5,259**
Carrying amounts				
Balance as at December 31, 2023	$ 5,442	$ 223	$ 18	$ 5,683
Balance as at March 31, 2024	**$ 5,374**	**$ 220**	**$ 17**	**$ 5,611**

At March 31, 2024, PP&E was assessed for indicators of impairment and none were identified. Assets under construction as at March 31, 2024 totaled $18 million (assets under construction as at December 31, 2023 - $13 million).

6. EXPLORATION AND EVALUATION ASSETS

As at March 31, 2024, E&E assets consist of $128 million in exploration projects which are pending the determination of proved or probable bitumen reserves (year ended December 31, 2023 – $128 million). These assets were assessed for indicators of impairment at March 31, 2024 and none were identified.

7. OTHER ASSETS

As at	March 31, 2024	December 31, 2023
Non-current pipeline linefill[(a)]	**$ 210**	$ 206
Finance sublease receivables	**9**	10
Prepaid transportation costs	**7**	8
Intangible assets	**3**	3
	229	227
Less current portion, included in accrued revenue and accounts receivable	**(2)**	(2)
	$ 227	$ 225

a. Non-current pipeline linefill on third-party owned pipelines is classified as a non-current asset as these transportation contracts expire after April 2025.

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at	March 31, 2024	December 31, 2023
Trade payables and other	**$ 452**	$ 475
Current liability for cash-settled stock-based compensation	**33**	24
	$ 485	$ 499

9. LONG-TERM DEBT

As at	March 31, 2024	December 31, 2023
Unsecured:		
7.125% senior unsecured notes (Mar 31, 2024 - US$153.2 million; due 2027; December 31, 2023 - US$258.2 million)	**$ 207**	$ 341
5.875% senior unsecured notes (Mar 31, 2024 - US$600 million; due 2029; December 31, 2023 - US$600 million)	**812**	792
	1,019	1,133
Unamortized deferred debt discount and debt issue costs	**(8)**	(9)
Debt redemption premium	**4**	—
	$ 1,015	$ 1,124

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3533 (December 31, 2023 – US$1 = C$1.3205).

On March 22, 2024, the Corporation redeemed US$105 million (approximately $142 million) of the 7.125% senior unsecured notes due February 2027 at a redemption price of 101.8%, plus accrued and unpaid interest, with an associated debt redemption premium of $3 million. The Corporation now expects to exercise the prepayment option to redeem the remaining US$153.2 million of 7.125% senior unsecured notes and recognized a $4 million debt redemption premium associated with the prepayment option. In total, the Corporation recognized debt extinguishment expense of $7 million for the three months ended March 31, 2024 within net finance expense (Note 15).

10. PROVISIONS AND OTHER LIABILITIES

As at	March 31, 2024	December 31, 2023
Lease liabilities[(a)]	**$ 256**	$ 259
Decommissioning provision[(b)]	**184**	210
Onerous contract[(c)]	**45**	47
Long-term incentive compensation liability	**2**	—
Provisions and other liabilities	**487**	516
Less current portion	**(35)**	(30)
Non-current portion	**$ 452**	$ 486

a. Lease liabilities:

As at	March 31, 2024	December 31, 2023
Balance, beginning of period	**$ 259**	$ 244
Modification	**—**	33
Payments	**(10)**	(41)
Interest expense	**6**	24
Foreign exchange impact	**1**	(1)
Balance, end of period	**256**	259
Less current portion	**(16)**	(15)
Non-current portion	**$ 240**	$ 244

The Corporation's minimum lease payments are as follows:

As at March 31		2024
Within one year	$	40
Later than one year but not later than five years		153
Later than five years		407
Minimum lease payments		600
Amounts representing finance charges		(344)
Net minimum lease payments	$	256

b. Decommissioning provision:

The following table presents the decommissioning provision associated with the reclamation and abandonment of the Corporation's PP&E and E&E assets:

As at		March 31, 2024		December 31, 2023
Balance, beginning of period	$	210	$	166
Changes in estimated life and estimated future cash flows		(27)		6
Changes in discount rates		—		30
Liabilities settled		(2)		(3)
Accretion		3		11
Balance, end of period		184		210
Less current portion		(10)		(6)
Non-current portion	$	174	$	204

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's PP&E and E&E assets. The total undiscounted amount of the estimated future cash flows to settle the decommissioning obligations is $868 million (December 31, 2023 – $831 million). At March 31, 2024, the Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 8.0% (December 31, 2023 – 8.0%) and an inflation rate of 2.1% (December 31, 2023 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2023 - periods up to the year 2066).

c. Onerous contract:

The onerous contract provision relates to an onerous marketing contract with a remaining term of 5 years. The provision represents the present value of the estimated future cash flows. The current portion of this onerous contract provision is $9 million.

11. 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 and the amount of share capital are as follows:

	Three months ended March 31, 2024		Year ended December 31, 2023	
	Number of shares (thousands)	**Amount**	**Number of shares (thousands)**	**Amount**
Balance, beginning of year	**274,642**	**$ 4,845**	291,081	$ 5,164
Issued upon exercise of stock options	**153**	**1**	139	2
Issued upon vesting and release of equity-settled RSUs and PSUs	**2,311**	**23**	2,377	13
Repurchase of shares for cancellation	**(4,730)**	**(83)**	(18,955)	(334)
Balance, end of period	**272,376**	**$ 4,786**	274,642	$ 4,845

On March 6, 2024, the Toronto Stock Exchange ("TSX") approved the renewal of the Corporation's normal course issuer bid ("NCIB"). Pursuant to the NCIB, MEG will purchase for cancellation, from time to time, as it considers advisable, up to a maximum of 24,007,526 common shares of the Corporation. The NCIB became effective on March 11, 2024 and will terminate on March 10, 2025 or such earlier time as the NCIB is completed or terminated at the option of MEG.

For the three months ended March 31, 2024, the Corporation repurchased for cancellation 4.7 million common shares under its NCIB at a weighted average price of $26.94 per share for a total cost of $127 million. Share capital was reduced by $83 million, reflecting the average carrying value of $17.63 per share. Retained earnings was reduced by $44 million for the repurchase price of shares above the carrying value.

During 2024, the Corporation issued approximately 2.3 million common shares upon vesting and release of restricted share units ("RSUs") and performance share units ("PSUs").

12. STOCK-BASED COMPENSATION

Three months ended March 31	**2024**	**2023**
Cash-settled expense(i)	**$ 11**	$ 18
Equity-settled expense	**7**	8
Realized equity price risk management (gain) loss(ii)	**—**	(87)
Unrealized equity price risk management (gain) loss(ii)	**—**	78
Stock-based compensation	**$ 18**	$ 17

(i) Cash-settled RSUs, PSUs and DSUs 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 equity price risk management contracts entered 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 were unrealized until vesting of the related units occurred. All financial equity price risk management contracts were fully realized as at March 31, 2023. See note 19(d) for further details.

An $11 million cash-settled expense was recognized during the three months ended March 31, 2024 due to the increase in the Corporation's share price and associated increase in value of cash-settled PSUs and deferred share units ("DSUs") compared to December 31, 2023. As at March 31, 2024, the Corporation recognized a current liability of $33 million and non-current liability of $3 million relating to the fair value of cash-settled PSUs and DSUs (December 31, 2023 – $24 million related to the fair value of cash-settled DSUs).

13. REVENUES

Three months ended March 31		2024		2023
Sales from:				
Production	$	1,153	$	1,043
Purchased product[i]		313		427
Petroleum revenue	$	1,466	$	1,470
Royalties		(128)		(31)
Petroleum revenue, net of royalties	$	1,338	$	1,439
Power revenue	$	25	$	40
Transportation revenue		1		1
Power and transportation revenue	$	26	$	41
Revenues	$	1,364	$	1,480

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

a. Disaggregation of revenue from contracts with customers

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

	Three months ended March 31											
	2024						2023					
	Petroleum Revenue						Petroleum Revenue					
		Proprietary		Third-party		Total		Proprietary		Third-party		Total
Country:												
Canada	$	541	$	43	$	584	$	395	$	95	$	490
United States		612		270		882		648		332		980
	$	1,153	$	313	$	1,466	$	1,043	$	427	$	1,470

For the three months ended March 31, 2024, power and transportation revenue of $26 million was attributed to Canada (March 31, 2023 – $41 million attributed to Canada).

b. Revenue-related assets

The Corporation has recognized the following revenue-related assets in accrued revenue and accounts receivable:

As at		March 31, 2024		December 31, 2023
Petroleum revenue	$	418	$	424
Power and transportation revenue		6		4
Total revenue-related assets	$	424	$	428

Revenue-related receivables are typically settled within 30 days. At March 31, 2024 and December 31, 2023, there was no material expected credit loss recorded against revenue-related receivables.

14. FOREIGN EXCHANGE (GAIN) LOSS, NET

Three months ended March 31	2024	2023
Unrealized foreign exchange (gain) loss on:		
Long-term debt	**$ 28**	$ —
US$ denominated cash and cash equivalents	**(6)**	1
Unrealized net (gain) loss on foreign exchange	**22**	1
Realized (gain) loss on foreign exchange	**1**	—
Foreign exchange (gain) loss, net	**$ 23**	$ 1

C$ equivalent of 1 US$		
Beginning of period	**1.3205**	1.3534
End of period	**1.3533**	1.3528

15. NET FINANCE EXPENSE

Three months ended March 31	2024	2023
Interest expense on long-term debt	**$ 19**	$ 26
Interest expense on lease liabilities	**6**	6
Credit facility fees	**3**	3
Interest income	**(3)**	(2)
Net interest expense	**25**	33
Debt extinguishment expense	**7**	4
Accretion on provisions	**3**	3
Net finance expense	**$ 35**	$ 40

For the three months ended March 31, 2024, debt extinguishment expense of $7 million was recognized which included $3 million associated with the redemption of US$105 million (approximately $142 million) of the Corporation's 7.125% senior unsecured notes and $4 million associated with the prepayment option on upcoming note redemptions. Refer to Note 9 for further details.

For the three months ended March 31, 2023, debt extinguishment expense of $4 million was recognized in association with the US$86 million (approximately $117 million) repurchase of the Corporation's 7.125% senior unsecured notes and included a cumulative debt redemption premium of $3 million and associated amortized deferred debt issue costs of $1 million.

16. INCOME TAX EXPENSE (RECOVERY)

Three months ended March 31	2024	2023
Current income tax expense (recovery)	**$ 1**	$ —
Deferred income tax expense	**38**	29
Income tax expense	**$ 39**	$ 29

17. SUPPLEMENTAL CASH FLOW DISCLOSURES

Three months ended March 31		2024		2023
Cash provided by (used in):				
Accrued revenue and accounts receivable	$	14	$	(100)
Inventories		(1)		(7)
Accounts payable and accrued liabilities		(17)		21
Interest payable		(19)		(28)
	$	(23)	$	(114)
Changes in non-cash working capital relating to:				
Operating	$	(12)	$	(111)
Investing		(7)		2
Financing		(4)		(5)
	$	(23)	$	(114)
Cash and cash equivalents:[(a)]				
Cash	$	85	$	85
Cash equivalents		—		—
	$	85	$	85
Cash interest paid	$	37	$	53

a. As at March 31, 2024, $74 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (March 31, 2023 – $55 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$1.3533 (March 31, 2023 – US$1 = C$1.3528).

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, 2023	$	10	$	259	$	1,124
Financing cash flow changes:						
Receipts on leased assets		(1)		—		—
Payments on leased liabilities		—		(4)		—
Repayment and redemption of long-term debt		—		—		(142)
Debt redemption premium		—		—		(4)
Other cash and non-cash changes:						
Interest payments on lease liabilities		—		(6)		—
Interest expense on lease liabilities		—		6		—
Unrealized (gain) loss on foreign exchange		—		1		28
Debt extinguishment expense		—		—		7
Amortization of deferred debt discount and debt issue costs		—		—		2
Balance as at March 31, 2024	$	9	$	256	$	1,015

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

18. NET EARNINGS PER COMMON SHARE

Three months ended March 31		2024		2023
Net earnings	$	98	$	81
Weighted average common shares outstanding (millions)[(a)]		273		289
Dilutive effect of stock options and equity-settled RSUs and PSUs (millions)		3		4
Weighted average common shares outstanding – diluted (millions)		276		293
Net earnings per share, basic	$	0.36	$	0.28
Net earnings per share, diluted	$	0.36	$	0.28

a. Weighted average common shares outstanding for the three months ended March 31, 2024 include 0.4 million PSUs vested but not yet released (three months ended March 31, 2023 - 0.4 million PSUs vested but not yet released).

19. 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 approximate the fair values of the respective assets and liabilities due to the short-term nature of those instruments.

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

As at	March 31, 2024				December 31, 2023			
		Carrying amount		Fair value		Carrying amount		Fair value
Recurring measurements:								
Financial assets								
Commodity risk management contracts	$	—	$	—	$	2	$	2
Financial liabilities								
Long-term debt (Note 9)	$	1,019	$	1,004	$	1,133	$	1,108
Commodity risk management contracts	$	18	$	18	$	24	$	24

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 at March 31, 2024 and is expected to fluctuate over time.

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

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

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

As at	**March 31, 2024**			**December 31, 2023**		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Gross amount	**$ —**	**$ (18)**	**$ (18)**	$ 2	$ (24)	$ (22)
Amount offset	**—**	**—**	**—**	—	—	—
Net amount	**$ —**	**$ (18)**	**$ (18)**	$ 2	$ (24)	$ (22)
Current portion	**$ —**	**$ (18)**	**$ (18)**	$ 2	$ (24)	$ (22)
Non-current portion	**—**	**—**	**—**	—	—	—
Net amount	**$ —**	**$ (18)**	**$ (18)**	$ 2	$ (24)	$ (22)

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

As at March 31	**2024**	**2023**
Risk management assets (liabilities), beginning of year	**$ (22)**	$ 60
Realized risk management (gain) loss on:		
Equity price risk management contracts	**—**	(87)
Commodity risk management contracts	**4**	(2)
Change in fair value on:		
Equity price risk management contracts(i)	**—**	9
Commodity risk management contracts(ii)	**—**	2
Risk management assets (liabilities), end of period	**$ (18)**	$ (19)

(i) Represents total equity price risk management (gain) loss recognized within stock-based compensation expense.
(ii) Represents total commodity risk management (gain) loss.

c. Commodity risk management:

The Corporation had the following financial commodity risk management contracts relating to natural gas purchases outstanding at March 31, 2024:

Natural Gas Purchase Contracts	**Volumes (GJ/d)**	**Term**	**Average Price (C$/GJ)**
AECO Fixed Price	30,000	Apr 1, 2024 - Dec 31, 2024	$4.11

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

The following table summarizes the sensitivity of the earnings (loss) before income tax to the impact of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place at March 31, 2024:

Commodity	Sensitivity Range	Increase	Decrease
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	**$ 4**	**$ (4)**

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

Three months ended March 31	2024	2023
Realized loss (gain) on commodity risk management	**$ 4**	$ (2)
Unrealized loss (gain) on commodity risk management	**(4)**	—
Commodity risk management (gain) loss, net	**$ —**	$ (2)

d. Equity price risk management:

In 2020, the Corporation entered 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 will impact earnings and cash flows. Earnings and funds flow from operating activities are impacted when outstanding cash-settled RSUs and PSUs, issued under the Corporation's stock-based compensation plans, are revalued each period based on the Corporation's share price and the revaluation is recognized in stock-based compensation expense. Net cash provided by (used in) operating activities is impacted when the cash-settled components of these stock-based compensation units are ultimately settled. The Corporation entered into equity price risk management contracts in March 2020 to manage its exposure on cash-settled RSUs and PSUs vesting between April 1, 2021 and March 31, 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 March 31	2024	2023
Realized equity price risk management (gain) loss	**$ —**	$ (87)
Unrealized equity price risk management (gain) loss	**—**	78
Equity price risk management (gain) loss	**$ —**	$ (9)

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 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. At March 31, 2024, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $452 million. 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.

The Corporation's cash balances are used to repay debt, fund capital expenditures and return capital to shareholders. The cash balances are held in high interest savings accounts or are invested in high grade, liquid, short-term instruments such as bankers' acceptances, commercial paper, money market deposits or similar instruments. The cash and cash equivalents balance at March 31, 2024 was $85 million. The Corporation's estimated maximum exposure to credit risk related to its cash and cash equivalents is $85 million.

f. Liquidity risk management:

Liquidity risk is the risk that the Corporation will not be able to meet 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 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 which minimize 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 US$153.2 million of 7.125% senior unsecured notes due February 2027 represents the earliest long-term debt maturity. None of the Corporation's outstanding long-term debt contains 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.

20. 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 capital expenditures, return capital to shareholders or fund future production growth. In the current price environment, management believes its 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 repurchases and capital expenditures are anticipated to be funded by the Corporation's adjusted funds flow, cash-on-hand and/or other available liquidity.

On March 6, 2024, the TSX approved the renewal of the Corporation's NCIB. Pursuant to the NCIB, MEG will purchase for cancellation, from time to time, as it considers advisable, up to a maximum of 24,007,526 common shares of the Corporation. The NCIB became effective on March 11, 2024 and will terminate on March 10, 2025 or such earlier time as the NCIB is completed or terminated at the option of MEG.

Currently, 50% of free cash flow is allocated to share repurchases with the remainder applied to debt repayment. This allocation will remain in place until net debt reaches US$600 million, which is expected to occur in the third quarter of 2024.

The following table summarizes the Corporation's net debt:

As at	Note	March 31, 2024	December 31, 2023
Long-term debt	9	**$ 1,015**	$ 1,124
Cash and cash equivalents		**(85)**	(160)
Net debt - C$		**$ 930**	$ 964
Net debt - US$		**$ 687**	$ 730

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

On March 22, 2024, the Corporation redeemed US$105 million (approximately $142 million) of the 7.125% senior unsecured notes at a redemption price of 101.8%, plus accrued and unpaid interest.

Beginning in the second quarter of 2022, the Corporation began repurchasing MEG common shares for cancellation under the Corporation's NCIB program. For the three months ended March 31, 2024, the Corporation repurchased for cancellation 4.7 million common shares totaling $127 million.

The Corporation has $1.2 billion of available credit, comprised of $600 million under a revolving credit facility and $600 million under a letter of credit facility guaranteed by Export Development Canada ("EDC Facility"). Letters of credit under the EDC Facility do not consume capacity of the revolving credit facility. The revolving credit facility and the EDC Facility have maturity dates of October 31, 2026 and are secured by substantially all the assets of the Corporation.

The revolving credit facility has a modified covenant-lite structure, meaning it contains no financial maintenance covenant unless the Corporation is drawn under the revolving credit facility in excess of 50%, or $300 million. 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 represented by US$153.2 million of 7.125% senior unsecured notes due February 2027. At March 31, 2024, the Corporation had $600 million unutilized capacity under the revolving credit facility and with $296 million of issued letters of credit, had $304 million of unutilized capacity under the $600 million EDC Facility.

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

Three months ended March 31	2024	2023
Funds flow from operating activities	**$ 329**	$ 348
Adjustments:		
Impact of cash-settled SBC units subject to equity price risk management	**—**	13
Realized equity price risk management gain	**—**	(87)
Adjusted funds flow	**329**	274
Capital expenditures	**(112)**	(113)
Free cash flow	**$ 217**	$ 161

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

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

21. COMMITMENTS AND CONTINGENCIES

a. Commitments

The Corporation's commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at March 31, 2024:

	2024	2025	2026	2027	2028	Thereafter	Total
Transportation and storage(i)	$ 366	$ 491	$ 490	$ 493	$ 498	$ 5,169	$ 7,507
Diluent purchases(ii)	231	45	5	—	—	—	281
Other operating commitments	14	18	18	9	9	59	127
Variable office lease costs	3	5	5	4	4	13	34
Capital commitments	45	—	—	—	—	—	45
Commitments	**$ 659**	**$ 559**	**$ 518**	**$ 506**	**$ 511**	**$ 5,241**	**$ 7,994**

(i) This represents transportation and storage commitments from 2024 to 2048, including the estimated TMX commitment which is not yet in service. Excludes amounts recognized on the consolidated balance sheet (Note 10).

(ii) The associated transportation commitment is included in transportation and storage.

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.