# MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three and six months ended June 30, 2024 was approved by the Corporation's Audit Committee on July 25, 2024. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three and six months ended June 30, 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:

| | Six months ended June 30 | | 2024 | | 2023 | | | | 2022 | |
|---|---|---|---|---|---|---|---|---|---|---|
| *($millions, except as indicated)* | **2024** | **2023** | **Q2** | **Q1** | **Q4** | **Q3** | **Q2** | **Q1** | **Q4** | **Q3** |
| **Operational results:** | | | | | | | | | | |
| Bitumen production - bbls/d | **102,309** | 96,349 | **100,531** | 104,088 | 109,112 | 103,726 | 85,974 | 106,840 | 110,805 | 101,983 |
| Steam-oil ratio | **2.40** | 2.25 | **2.44** | 2.37 | 2.28 | 2.28 | 2.25 | 2.25 | 2.22 | 2.39 |
| Bitumen sales - bbls/d | **99,337** | 94,942 | **93,140** | 105,534 | 112,634 | 101,625 | 83,531 | 106,480 | 113,582 | 95,759 |
| **Benchmark pricing:** | | | | | | | | | | |
| WTI - US$/bbl | **78.77** | 74.95 | **80.57** | 76.96 | 78.32 | 82.26 | 73.78 | 76.13 | 82.65 | 91.55 |
| Differential - WTI:WCS - Edmonton - US$/bbl | **(16.46)** | (20.02) | **(13.61)** | (19.31) | (21.89) | (12.91) | (15.16) | (24.88) | (25.89) | (19.86) |
| AWB - Edmonton - US$/bbl | **60.98** | 52.45 | **65.99** | 55.96 | 54.53 | 67.88 | 56.41 | 48.50 | 53.51 | 68.75 |
| **Financial results:** | | | | | | | | | | |
| Bitumen realization after net transportation and storage expense[1] - $/bbl | **66.55** | 49.69 | **73.84** | 60.10 | 63.52 | 84.75 | 57.64 | 43.40 | 54.75 | 74.75 |
| Non-energy operating costs[2] - $/bbl | **5.39** | 5.17 | **5.63** | 5.18 | 4.64 | 5.15 | 5.66 | 4.77 | 4.34 | 4.49 |
| Energy operating costs net of power revenue[1] - $/bbl | **1.10** | 1.18 | **0.99** | 1.19 | 1.46 | (0.04) | 0.97 | 1.36 | 1.49 | 0.96 |
| Operating expenses net of power revenue[1] - $/bbl | **6.49** | 6.35 | **6.62** | 6.37 | 6.10 | 5.11 | 6.63 | 6.13 | 5.83 | 5.45 |
| Cash operating netback[1] - $/bbl | **43.34** | 37.89 | **47.14** | 39.99 | 38.65 | 58.64 | 42.38 | 34.32 | 43.89 | 62.63 |
| General & administrative expense - $/bbl of bitumen production volumes | **2.08** | 1.90 | **1.98** | 2.18 | 1.89 | 1.73 | 1.85 | 1.94 | 1.62 | 1.72 |
| Royalties | **290** | 89 | **162** | 128 | 186 | 181 | 58 | 31 | 54 | 66 |
| Funds flow from operating activities | **683** | 626 | **354** | 329 | 358 | 492 | 278 | 348 | 383 | 501 |
| Per share, diluted | **2.49** | 2.15 | **1.30** | 1.19 | 1.27 | 1.71 | 0.96 | 1.19 | 1.28 | 1.63 |
| Adjusted funds flow[3] | **683** | 552 | **354** | 329 | 358 | 492 | 278 | 274 | 401 | 496 |
| Per share, diluted[3] | **2.49** | 1.90 | **1.30** | 1.19 | 1.27 | 1.71 | 0.96 | 0.94 | 1.34 | 1.61 |
| Capital expenditures | **235** | 262 | **123** | 112 | 104 | 83 | 149 | 113 | 106 | 78 |
| Free cash flow[3] | **448** | 290 | **231** | 217 | 254 | 409 | 129 | 161 | 295 | 418 |
| Debt repayments - US$ | **158** | 126 | **53** | 105 | 128 | 68 | 40 | 86 | 150 | 262 |
| Share repurchases - C$ | **195** | 169 | **68** | 127 | 219 | 58 | 66 | 103 | 196 | 92 |
| Revenues | **2,737** | 2,771 | **1,373** | 1,364 | 1,444 | 1,438 | 1,291 | 1,480 | 1,445 | 1,571 |
| Net earnings (loss) | **234** | 217 | **136** | 98 | 103 | 249 | 136 | 81 | 159 | 156 |
| Per share, diluted | **0.86** | 0.74 | **0.50** | 0.36 | 0.37 | 0.86 | 0.47 | 0.28 | 0.53 | 0.51 |
| Long-term debt, including current portion | **954** | 1,382 | **954** | 1,015 | 1,124 | 1,323 | 1,382 | 1,466 | 1,581 | 1,803 |
| Net debt[3] - US$ | **634** | 994 | **634** | 687 | 730 | 885 | 994 | 1,020 | 1,026 | 1,193 |

(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.*

The Corporation generated funds flow from operating activities and adjusted funds flow of $354 million during the three months ended June 30, 2024. After $123 million of capital expenditures, the Corporation's remaining free cash flow of $231 million was used to redeem debt, return capital to shareholders and fund working capital requirements. During the three months ended June 30, 2024, the Corporation redeemed US$53 million (approximately $73 million) of outstanding 7.125% senior unsecured notes at a redemption price of 101.8% and returned $68 million to MEG shareholders through the repurchase and cancellation of 2.2 million shares at a weighted-average price of $30.39 per share.

Average bitumen production volumes during the second quarter of 2024 rose 17% to 100,531 barrels per day at a steam-oil ratio ("SOR") of 2.44, from 85,974 barrels per day at an SOR of 2.25 in the same period of 2023. The increased production volumes primarily reflect the impact of a major planned turnaround at the Christina Lake Facility during the second quarter of 2023, whereas turnaround activities in 2024 are reduced and spread more evenly throughout the year. The higher SOR in the second quarter of 2024 primarily reflects the planned timing of injecting steam in new well starts.

During the three months ended June 30, 2024, funds flow from operating activities and adjusted funds flow increased to $354 million from $278 million in the same period of 2023. The increase was driven mainly by a higher cash operating netback per barrel, increased sales volumes and lower interest expense due to reduced debt levels. Cash operating netback rose $4.76 per barrel to $47.14 per barrel 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 $73.84 per barrel from $57.64 per barrel driven by a higher average WTI benchmark price, narrower WTI:AWB differentials, lower diluent expense and reduced net transportation and storage expense partially offset by a lower contribution to overall price realization from USGC sales and marketing optimization activities.

Capital expenditures in the second quarter of 2024 decreased to $123 million from $149 million in the same period of 2023. Spending in both periods was primarily focused on sustaining and maintenance activities. Capital expenditures in the second quarter of 2023 reflect a major planned turnaround at the Christina Lake Facility while turnaround activities in 2024 are reduced and spread more evenly throughout the year. This decrease was partially offset by higher planned well development and associated infrastructure spending together with the onset of investment in moderate capacity growth projects.

Free cash flow in the second quarter of 2024 increased to $231 million from $129 million in the same period of 2023.

During the six months ended June 30, 2024, the Corporation generated funds flow from operating activities and adjusted funds flow of $683 million. After $235 million of capital expenditures, the Corporation's remaining free cash flow of $448 million was used to redeem debt, return capital to shareholders and fund working capital requirements. During the first half of 2024, the Corporation redeemed US$158 million (approximately $215 million) of outstanding 7.125% senior unsecured notes at a redemption price of 101.8% and returned $195 million to MEG shareholders through the repurchase and cancellation of 7.0 million shares at a weighted-average price of $28.05 per share.

Net earnings remained flat at $136 million across the second quarters of 2024 and 2023 as higher adjusted funds flow in the second quarter of 2024 was offset by an unrealized foreign exchange loss on long-term debt, higher depletion and depreciation expense and increased deferred tax expense.

Cash and cash equivalents were $86 million at June 30, 2024. The Corporation exited the second quarter of 2024 with total debt and net debt of $954 million and $868 million (US$634 million), respectively.

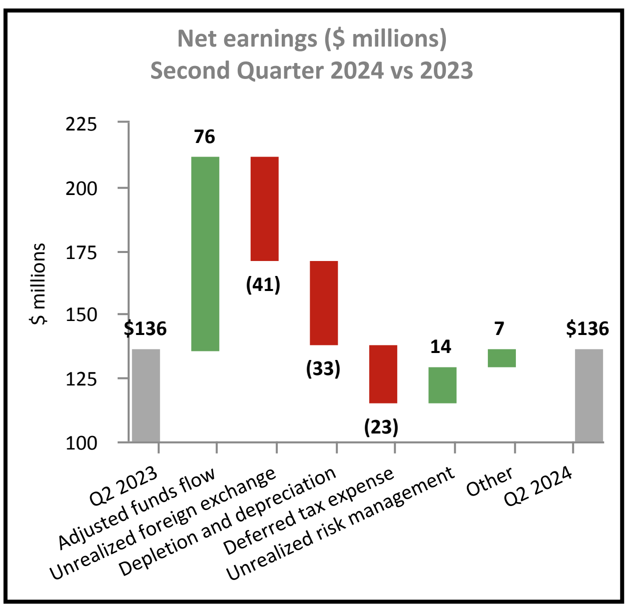
On July 25, 2024, the Corporation’s Board of Directors approved the initiation of a base dividend program under which the Corporation intends to pay a cash dividend each quarter, subject to Board of Directors’ approval. An inaugural cash dividend of $0.10 per share has been declared for payment on October 15, 2024 to shareholders of record on September 17, 2024. This dividend equates to an approximate 1.5% annual yield at MEG’s current share price, a level that is positioned to grow through disciplined capital allocation.

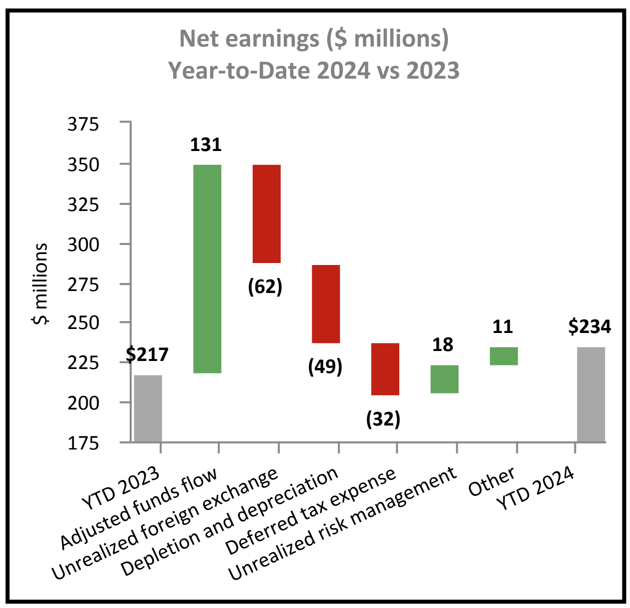
## 2. SUSTAINABILITY AND PATHWAYS UPDATE

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 passed Bill C-59, which received Royal Assent on June 20, 2024 and implemented an investment tax credit ("ITC") for CCS projects for all sectors across Canada. In addition, the Alberta Government announced an Alberta Carbon Capture Incentive Program ("ACCIP"), which aims to help hard-to-abate industries by providing a grant of 12% for new eligible CCS capital costs. ACCIP is being designed to align with the federal CCS ITC and will be finalized after the federal government legislates its CCS ITC and related operating supports, such as contracts for difference. The Pathways Alliance is evaluating these proposals.

Bill C-59 also implemented amendments to the Competition Act related to public statements made by an entity regarding actions taken to protect or restore the environment or mitigate the effects of climate change. The amendments create significant uncertainty as to how Canadian companies may publicly communicate about their environmental and climate performance, and progress and impose significant financial penalties for noncompliance. The Canadian Competition Bureau has indicated that guidance regarding the amendments will be provided but it has not been released to date. As a result, MEG has temporarily removed certain voluntary public disclosures from its website and other social media and is temporarily suspending its 2030 and 2050 GHG emissions[1] targets until such time as clarity is provided by the Canadian Competition Bureau regarding the application and interpretation of the new amendments. MEG remains fully committed to environmental and climate performance and the work it is doing to reduce GHG emissions and will continue to advance its initiatives notwithstanding the cautionary steps it has taken with respect to its environmental disclosure and climate-related targets.

## 3. NET EARNINGS




[1] Scope 1 and 2 GHG Emissions

Net earnings remained flat at $136 million across the three months ended June 30, 2024 and 2023 as higher adjusted funds flow in the second quarter of 2024 was offset by an unrealized foreign exchange loss on long-term debt, higher depletion and depreciation expense and increased deferred tax expense.

Net earnings increased to $234 million during the six months ended June 30, 2024 from $217 million in the same period of 2023 primarily driven by higher adjusted funds flow and an unrealized gain on risk management 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Sales from: | | | | |
| Production | **$ 1,179** | $ 942 | **$ 2,332** | $ 1,985 |
| Purchased product[1] | **346** | 383 | **659** | 810 |
| Petroleum revenue | **$ 1,525** | $ 1,325 | **$ 2,991** | $ 2,795 |
| Royalties | **(162)** | (58) | **(290)** | (89) |
| Petroleum revenue, net of royalties | **$ 1,363** | $ 1,267 | **$ 2,701** | $ 2,706 |
| Power revenue | **$ 10** | $ 23 | **$ 35** | $ 63 |
| Transportation revenue | **—** | 1 | **1** | 2 |
| Power and transportation revenue | **$ 10** | $ 24 | **$ 36** | $ 65 |
| Revenues | **$ 1,373** | $ 1,291 | **$ 2,737** | $ 2,771 |

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

During the three months ended June 30, 2024, petroleum revenue, net of royalties increased to $1.4 billion from $1.3 billion in the same period of 2023. Petroleum revenue, net of royalties was $2.7 billion in the first six months of both years. Higher blend sales volumes and prices during the three and six months ended June 30, 2024 were offset by increased royalties and reduced sales from purchased product.

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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| | **2024** | **2023** | **2024** | **2023** |
| Bitumen production – bbls/d | **100,531** | 85,974 | **102,309** | 96,349 |
| Steam-oil ratio (SOR) | **2.44** | 2.25 | **2.40** | 2.25 |

### Bitumen Production

Bitumen production increased 17% and 6% in the three and six months ended June 30, 2024, respectively, from the comparative 2023 periods. The production volume increases primarily reflect the impact of a major planned turnaround at the Christina Lake Facility during the second quarter of 2023, whereas turnaround activities in 2024 are reduced and spread more evenly throughout the year. Production during the first half of 2024 was also impacted by cold weather and the timing of new well start-ups.

### Steam-Oil Ratio

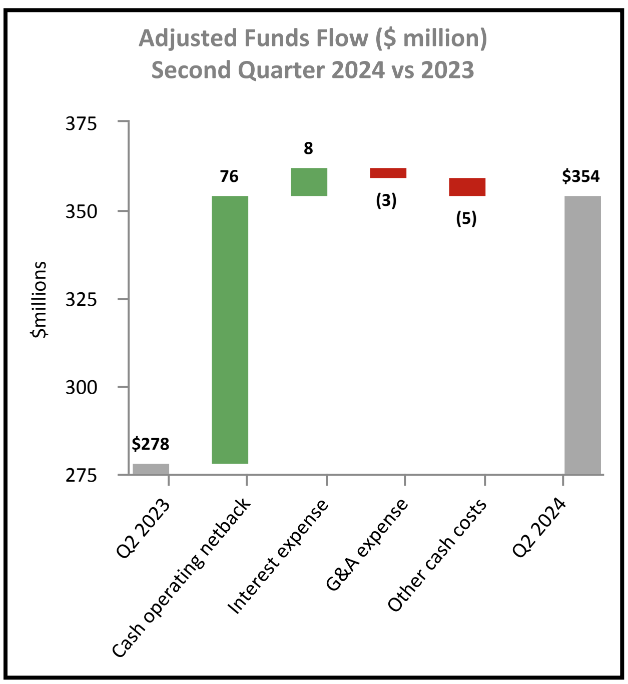
The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is SOR, which is an efficiency indicator that measures the amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR increased 8% and 7% during the three and six months ended June 30, 2024, respectively, compared to the same periods of 2023, primarily due to planned timing of injecting steam in advance of production from new well starts.

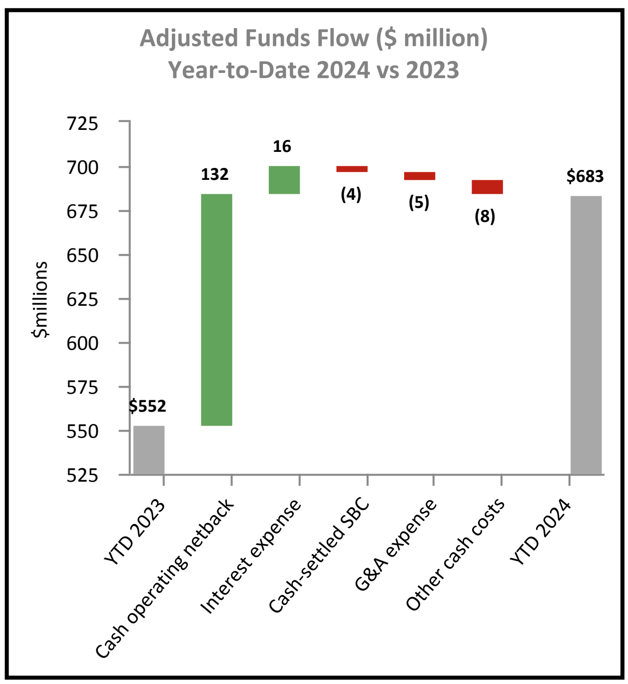
### Funds Flow from Operating Activities and Adjusted Funds Flow

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 June 30** | | **Six months ended June 30** | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Funds flow from operating activities | **$ 354** | $ 278 | **$ 683** | $ 626 |
| Adjustments: | | | | |
| Impact of cash-settled SBC units subject to equity price risk management | **—** | — | **—** | 13 |
| Realized equity price risk management gain | **—** | — | **—** | (87) |
| Adjusted funds flow | **$ 354** | $ 278 | **$ 683** | $ 552 |
| Per share, diluted | **$ 1.30** | $ 0.96 | **$ 2.49** | $ 1.90 |



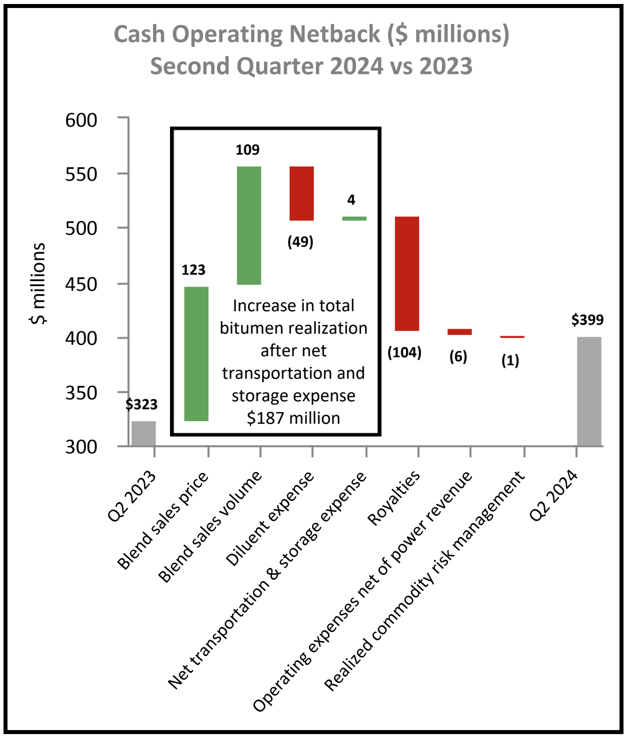
Funds flow from operating activities and adjusted funds flow increased in the three and six months ended June 30, 2024, compared to the same periods of 2023, driven mainly by a higher cash operating netback per barrel, increased sales volumes and lower interest expense due to reduced debt levels.

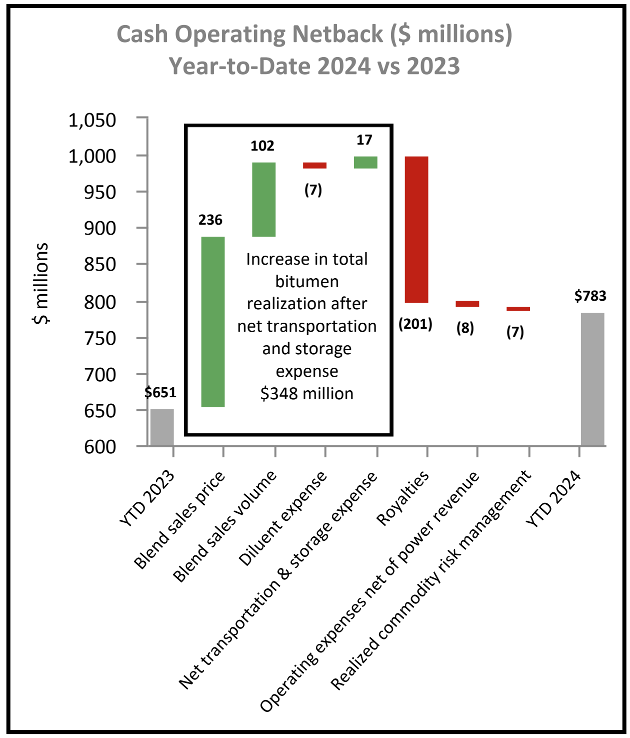
### Cash Operating Netback

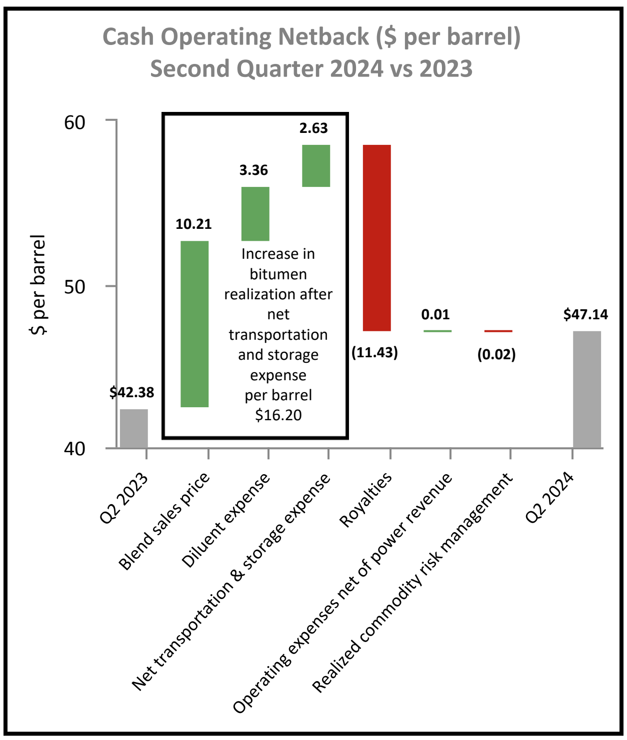
The following table summarizes the Corporation's cash operating netback. Unless otherwise indicated, the per barrel calculations are based on bitumen sales volumes.

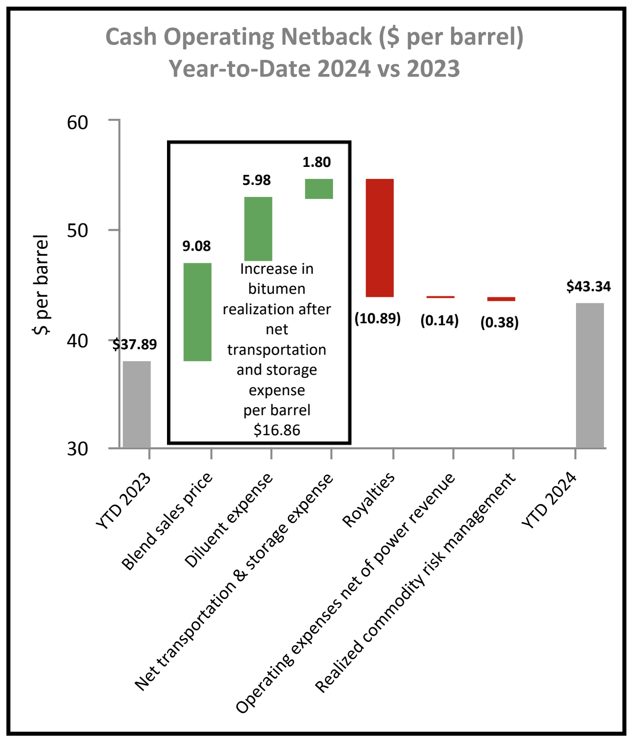
| | Three months ended June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | **2024** | | **2023** | | **2024** | | **2023** | |
| *($millions, except as indicated)* | | **$/bbl** | | **$/bbl** | | **$/bbl** | | **$/bbl** |
| Sales from production | **$ 1,179** | | $ 942 | | **$ 2,332** | | $ 1,985 | |
| Sales from purchased product[1] | **346** | | 383 | | **659** | | 810 | |
| Petroleum revenue | **$ 1,525** | | $ 1,325 | | **$ 2,991** | | $ 2,795 | |
| Purchased product[1] | **(341)** | | (373) | | **(645)** | | (787) | |
| Blend sales[2][3] | **$ 1,184** | **$ 98.02** | $ 952 | $ 87.81 | **$ 2,346** | **$ 90.30** | $ 2,008 | $ 81.22 |
| Diluent expense | **(412)** | **(6.91)** | (363) | (10.27) | **(868)** | **(8.50)** | (861) | (14.48) |
| Bitumen realization[3] | **$ 772** | **$ 91.11** | $ 589 | $ 77.54 | **$ 1,478** | **$ 81.80** | $ 1,147 | $ 66.74 |
| Net transportation and storage expense[3][4] | **(147)** | **(17.27)** | (151) | (19.90) | **(276)** | **(15.25)** | (293) | (17.05) |
| Bitumen realization after net transportation and storage expense[3] | **625** | **73.84** | 438 | 57.64 | **1,202** | **66.55** | 854 | 49.69 |
| Royalties | **(162)** | **(19.12)** | (58) | (7.69) | **(290)** | **(16.06)** | (89) | (5.17) |
| Operating expenses net of power revenue[3] | **(56)** | **(6.62)** | (50) | (6.63) | **(117)** | **(6.49)** | (109) | (6.35) |
| Realized gain (loss) on commodity risk management | **(8)** | **(0.96)** | (7) | (0.94) | **(12)** | **(0.66)** | (5) | (0.28) |
| Cash operating netback[3] | **$ 399** | **$ 47.14** | $ 323 | $ 42.38 | **$ 783** | **$ 43.34** | $ 651 | $ 37.89 |
| Bitumen sales volumes - bbls/d | | **93,140** | | 83,531 | | **99,337** | | 94,942 |

*(1) Sales and purchases of oil products related to marketing asset optimization activities.*
*(2) Blend sales per barrel are based on blend sales volumes.*
*(3) Non-GAAP financial measure - please refer to section 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 and six months ended June 30, 2024, cash operating netback, on a total and per barrel basis, increased compared to the same periods of 2023, mainly reflecting a higher bitumen realization after net transportation and storage expense partially offset by increased royalties.

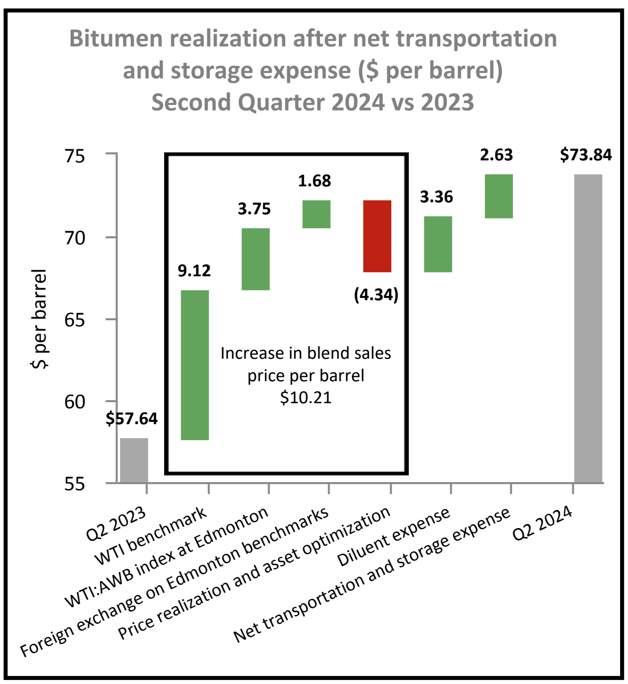
### Bitumen Realization after Net Transportation and Storage Expense

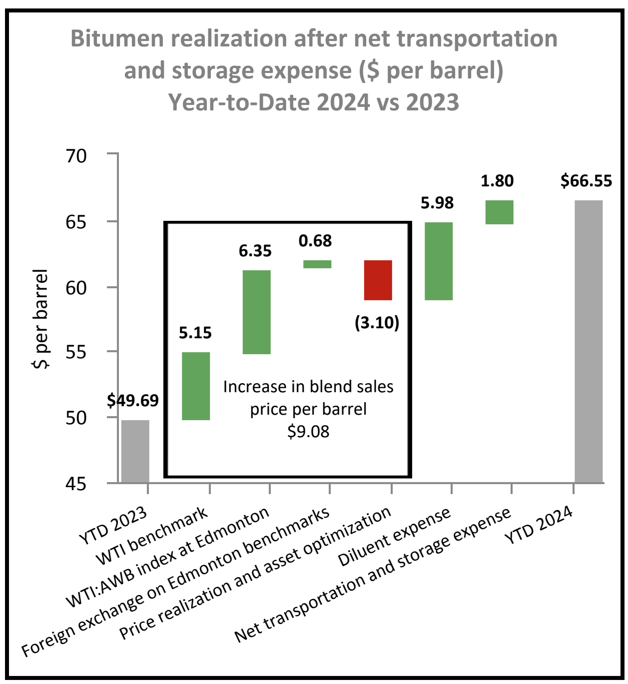
Bitumen realization after net transportation and storage expense reflects the realized bitumen price at Christina Lake and is calculated as blend sales less diluent expense and net transportation and storage expense. Blend sales represents the Corporation's revenue from its oil blend known as AWB, which 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 June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2024 | | 2023 | | 2024 | | 2023 | |
| *($millions, except as indicated)* | | $/bbl | | $/bbl | | $/bbl | | $/bbl |
| Sales from production | **$ 1,179** | | $ 942 | | **$ 2,332** | | $ 1,985 | |
| Sales from purchased product[1] | **346** | | 383 | | **659** | | 810 | |
| Petroleum revenue | **$ 1,525** | | $ 1,325 | | **$ 2,991** | | $ 2,795 | |
| Purchased product[1] | **(341)** | | (373) | | **(645)** | | (787) | |
| Blend sales[2][3] | **$ 1,184** | **$ 98.02** | $ 952 | $ 87.81 | **$ 2,346** | **$ 90.30** | $ 2,008 | $ 81.22 |
| Diluent expense | **(412)** | **(6.91)** | (363) | (10.27) | **(868)** | **(8.50)** | (861) | (14.48) |
| Bitumen realization[3] | **$ 772** | **$ 91.11** | $ 589 | $ 77.54 | **$ 1,478** | **$ 81.80** | $ 1,147 | $ 66.74 |
| Net transportation and storage expense[3] | **(147)** | **(17.27)** | (151) | (19.90) | **(276)** | **(15.25)** | (293) | (17.05) |
| Bitumen realization after net transportation and storage expense[3] | **$ 625** | **$ 73.84** | $ 438 | $ 57.64 | **$ 1,202** | **$ 66.55** | $ 854 | $ 49.69 |
| Bitumen sales volumes - bbls/d | | **93,140** | | 83,531 | | **99,337** | | 94,942 |

(1) *Sales and purchases of oil products related to marketing asset optimization activities.*
(2) *Blend sales per barrel are based on blend sales volumes.*
(3) *Non-GAAP financial measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.*



Bitumen realization after net transportation and storage expense increased 28% and 34%, to $73.84 and $66.55 per barrel, in the three and six months ended June 30, 2024, respectively, from $57.64 and $49.69 per barrel in the same periods of 2023. The increases were driven by a higher average WTI benchmark price, narrower WTI:AWB differentials, lower diluent expense and reduced net transportation and storage expense, partially offset by a lower contribution to overall price realization from USGC sales and marketing optimization activities.

Diluent expense per barrel, which reflects the purchased cost of diluent not recovered through blend sales, is impacted by condensate prices relative to WTI and the WTI:AWB differential. Diluent expense per barrel in the three and six months ended June 30, 2024 decreased to $6.91 and $8.50, respectively, from $10.27 and $14.48 in the same periods of 2023. The Corporation recovered 86% of diluent costs through blend sales during the second quarter of 2024 compared to 79% in the same period of 2023 as condensate prices decreased relative to WTI. The Corporation recovered 82% of diluent costs through blend sales during the six months ended June 30, 2024 compared to 71% in the same period of 2023 as condensate prices decreased relative to WTI and WTI:AWB differentials narrowed.

Total diluent expense, which reflects the purchased cost of diluent before recoveries through blend sales, is impacted by absolute condensate prices and purchased volumes. Total diluent expense increased to $412 million and $868 million in the three and six months ended June 30, 2024, respectively, from $363 million and $861 million in the comparative 2023 periods. The increases in the 2024 periods reflect higher diluent volumes, commensurate with higher sales volumes. This was partially offset by a lower average condensate price for the six months ended June 30, 2024.

| | Three months ended June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2024 | | 2023 | | 2024 | | 2023 | |
| *($millions, except as indicated)* | | **$/bbl** | | **$/bbl** | | **$/bbl** | | **$/bbl** |
| Transportation and storage expense | **$ (147)** | **$(17.34)** | $ (152) | $(20.01) | **$ (277)** | **$(15.32)** | $ (295) | $(17.15) |
| Transportation revenue | **—** | **0.07** | 1 | 0.11 | **1** | **0.07** | 2 | 0.10 |
| Net transportation and storage expense | **$ (147)** | **$(17.27)** | $ (151) | $(19.90) | **$ (276)** | **$(15.25)** | $ (293) | $(17.05) |
| Bitumen sales volumes - bbls/d | | **93,140** | | 83,531 | | **99,337** | | 94,942 |

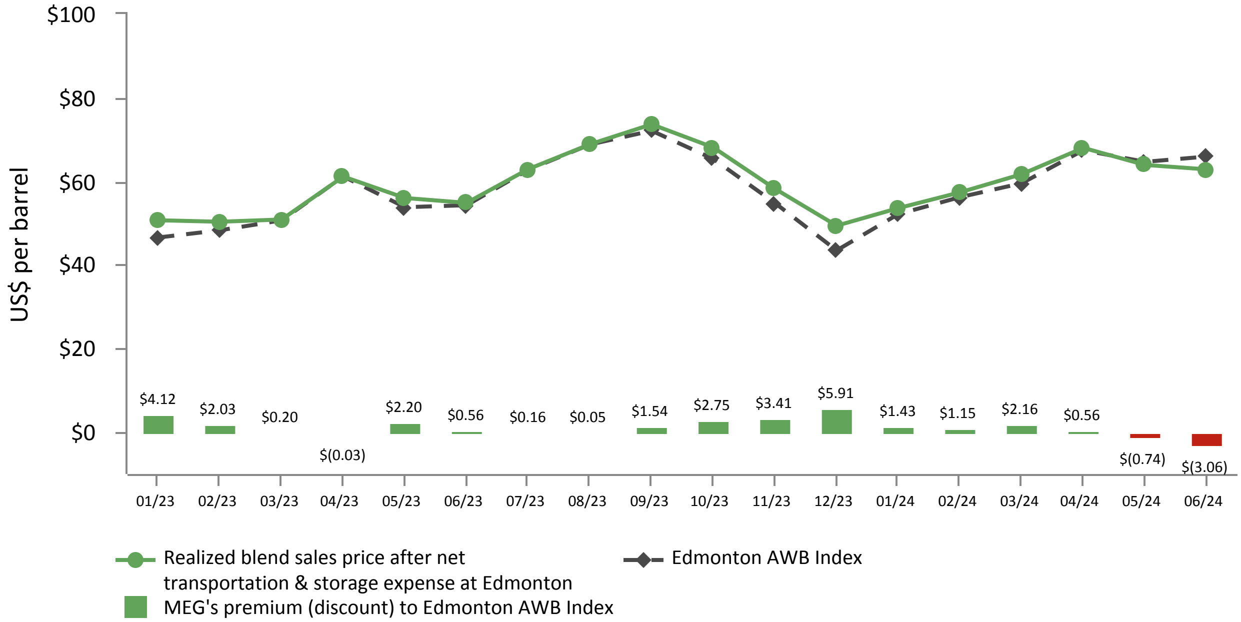
Net transportation and storage expense in the three and six months ended June 30, 2024, on a total and per barrel basis, declined relative to the same periods of 2023 reflecting higher pipeline apportionment, which lowered volumes transported to the USGC, partially offset by higher per barrel USGC pipeline tolls and new tolls on volumes transported to the West Coast of Canada on the Trans Mountain Expansion ("TMX") Pipeline. With the start-up of the TMX Pipeline, the Corporation began shipping AWB to Canada's West Coast under its 20,000 bbls/d contracted transportation capacity arrangement.

When expressed on a US$ per barrel of blend sales basis, net transportation and storage expenses were US$8.85 and US$7.81, respectively, during the three and six months ended June 30, 2024 compared to US$10.39 and US$8.79 during the same periods of 2023.

The Corporation partially reduced the cost of transportation and storage assets through the purchase and sale of non-proprietary product. These asset optimization activities contributed $5 million, or $0.43 per barrel, and $14 million, or $0.56 per barrel, to blend sales in the three and six months ended June 30, 2024, respectively, compared to $10 million, or $0.90 per barrel, and $23 million, or $0.92 per barrel of blend sales, in the same periods of 2023.

Long-term transportation and storage assets are strategically utilized to access diverse global markets and 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 the average sales price achieved through long-term market diversification relative to local markets.

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




In the three and six months ended June 30, 2024, the Corporation's overall average realized price on all blend sales saw a discount of US$1.13 per barrel and a premium of US$0.29 per barrel, respectively, compared to the Edmonton AWB index.

With the start-up of TMX, pipeline egress from Western Canada is unconstrained and heavy oil differentials have narrowed with anticipated lower volatility relative to historic levels. In this light:heavy oil environment, the Edmonton market will typically outperform global prices after netting transportation and storage commitments utilized by the Corporation to reach tidewater. As western Canadian production grows and egress fills, this trend is expected to reverse and the historic benefits of MEG's pipeline transportation commitments are expected to return.

### Royalties

The Oil Sands Royalty Regulation, 2009, establishes royalty rates that are linked to the WTI price 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Bitumen realization[1] | **$ 772** | $ 589 | **$ 1,478** | $ 1,147 |
| Transportation and storage expense | **(147)** | (152) | **(277)** | (295) |
| Transportation revenue | **—** | 1 | **1** | 2 |
| Bitumen realization after net transportation and storage expense[1] | **$ 625** | $ 438 | **$ 1,202** | $ 854 |
| Royalties | **$ 162** | $ 58 | **$ 290** | $ 89 |
| Effective royalty rate[1][2] | **25.9 %** | 13.2 % | **24.1 %** | 10.4 % |

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

The Corporation's Christina Lake operation reached payout status during the second quarter of 2023 at which point royalties are determined on a net revenue basis using a higher royalty rate. As a result, royalty expense and the effective royalty rate increased in the three and six months ended June 30, 2024 relative to the comparative 2023 periods. The higher royalty expense and effective royalty rate in the second quarter of 2024, relative to the same period in 2023, were also impacted by higher net revenues.

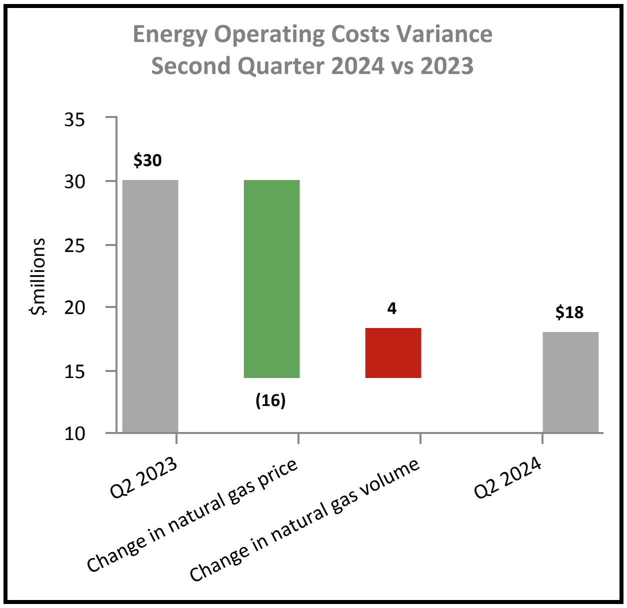
### Operating Expenses net of Power Revenue

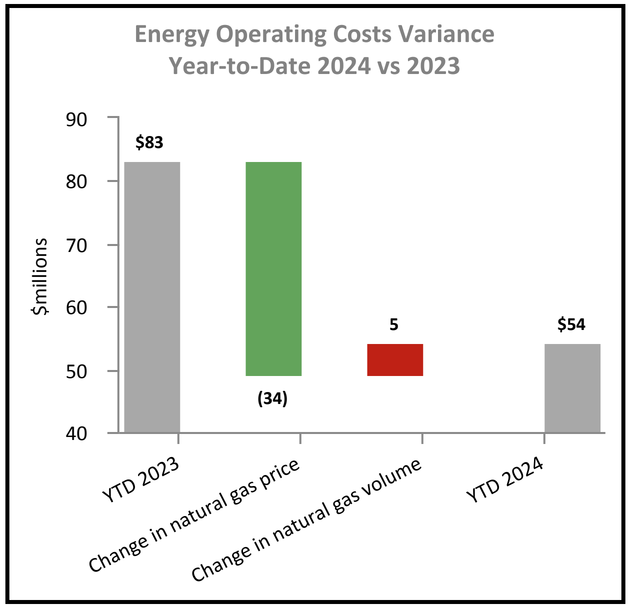
Operating expenses net of power revenue are comprised of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-oriented operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate steam and power. Power revenue is recognized from the sale of surplus power generated by the Corporation's cogeneration facilities.

| | Three months ended June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | **2024** | | **2023** | | **2024** | | **2023** | |
| *($millions, except as indicated)* | | **$/bbl** | | **$/bbl** | | **$/bbl** | | **$/bbl** |
| Non-energy operating costs[1] | **$ (48)** | **$ (5.63)** | $ (43) | $ (5.66) | **$ (98)** | **$ (5.39)** | $ (89) | $ (5.17) |
| Energy operating costs[1] | **(18)** | **(2.13)** | (30) | (3.92) | **(54)** | **(2.99)** | (83) | (4.84) |
| Operating expenses | **(66)** | **(7.76)** | (73) | (9.58) | **(152)** | **(8.38)** | (172) | (10.01) |
| Power revenue | **10** | **1.14** | 23 | 2.95 | **35** | **1.89** | 63 | 3.66 |
| Operating expenses net of power revenue[2] | **$ (56)** | **$ (6.62)** | $ (50) | $ (6.63) | **$ (117)** | **$ (6.49)** | $ (109) | $ (6.35) |
| Energy operating costs net of power revenue[2] | **$ (8)** | **$ (0.99)** | $ (7) | $ (0.97) | **$ (19)** | **$ (1.10)** | $ (20) | $ (1.18) |
| Average delivered natural gas price (C$/mcf) | | **$ 1.58** | | $ 3.04 | | **$ 2.32** | | $ 3.86 |
| Average realized power sales price (C$/Mwh) | | **$ 45.57** | | $150.19 | | **$ 75.76** | | $158.10 |

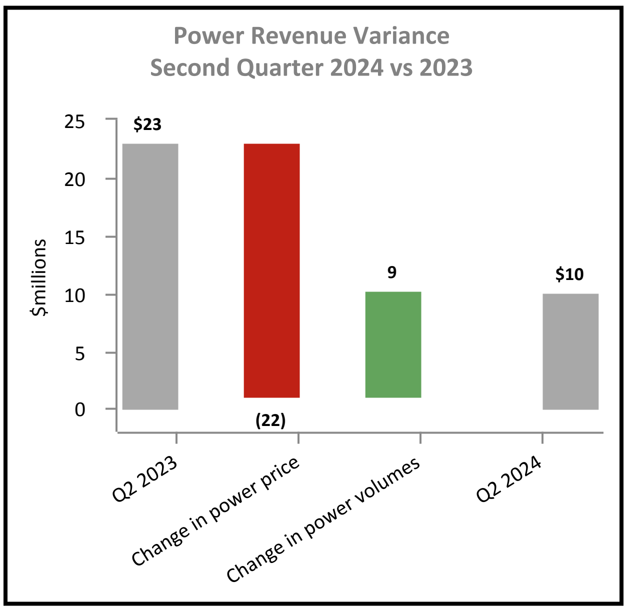
*(1) Supplementary financial measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.*
*(2) Non-GAAP financial measure - please refer to section 13 "Non-GAAP and Other Financial Measures" of this MD&A.*

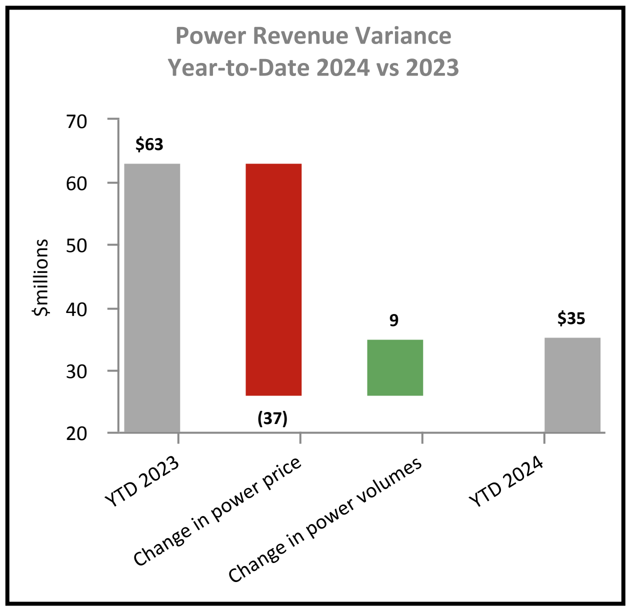
Total non-energy operating costs increased in the three and six months ended June 30, 2024, compared to the same periods of 2023, reflecting an expected increase in labour costs, maintenance activity and treating chemical costs. On a per barrel basis, the impact of these factors was offset by higher bitumen sales volumes in the 2024 periods compared to 2023.




Lower energy operating costs in the three and six months ended June 30, 2024, on a total and per barrel basis, reflect a weaker AECO natural gas price, partially offset by higher natural gas volumes, relative to the same periods of 2023.




Power revenue during the three and six months ended June 30, 2024 declined compared to the same periods of 2023, reflecting 70% and 52% respective decreases in the realized price partially offset by higher sales volumes.

Energy operating costs net of power revenue were $0.99 per barrel during the three months ended June 30, 2024, consistent with the comparable 2023 period, as lower power revenue was largely offset by a weaker AECO natural gas price.

In the six months ended June 30, 2024 energy operating costs net of power revenue per barrel decreased to $1.10 from $1.18 during the comparable 2023 period with a weaker AECO natural gas price more than offsetting the lower power revenue.

### Capital Expenditures

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Sustaining and maintenance | **$ 110** | $ 83 | **$ 220** | $ 196 |
| Capacity growth | **11** | — | **13** | — |
| Turnaround | **2** | 66 | **2** | 66 |
| | **$ 123** | $ 149 | **$ 235** | $ 262 |

Lower capital expenditures in the three and six months ended June 30, 2024, relative to the same periods of 2023, primarily reflect a decrease in the scope and timing of planned turnaround activities. The Corporation performed a major turnaround at the Christina Lake Facility in the second quarter of 2023 while turnaround activities in 2024 are reduced and spread more evenly throughout the year. This decrease was partially offset by higher planned well development and associated infrastructure together with the onset of investment in moderate capacity growth projects.

## 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 |

Production in the first half of 2024 was 102,309 barrels per day, and is forecast to grow during the second half of the year as new wells come online. The increased production will also reduce costs on a per barrel basis bringing annual costs within the guidance ranges.

## 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 PRICE INDICES | Six months ended June 30 | | 2024 | | 2023 | | | | 2022 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2024 | 2023 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 |
| **Crude oil prices** | | | | | | | | | | |
| Brent (US$/bbl) | **83.42** | 80.11 | **84.99** | 81.85 | 81.61 | 85.95 | 78.01 | 82.21 | 88.59 | 97.69 |
| WTI (US$/bbl) | **78.77** | 74.95 | **80.57** | 76.96 | 78.32 | 82.26 | 73.78 | 76.13 | 82.65 | 91.55 |
| Differential – WTI:WCS – Edmonton (US$/bbl) | **(16.46)** | (20.02) | **(13.61)** | (19.31) | (21.89) | (12.91) | (15.16) | (24.88) | (25.89) | (19.86) |
| AWB – Edmonton (US$/bbl) | **60.98** | 52.45 | **65.99** | 55.96 | 54.53 | 67.88 | 56.41 | 48.50 | 53.51 | 68.75 |
| **Condensate prices** | | | | | | | | | | |
| Condensate at Edmonton (C$/bbl) | **101.87** | 102.55 | **105.56** | 98.18 | 103.90 | 104.62 | 97.19 | 107.91 | 113.17 | 113.97 |
| Condensate at Edmonton as a % of WTI | **95.2** | 101.5 | **95.7** | 94.6 | 97.4 | 94.8 | 98.1 | 104.8 | 100.9 | 95.3 |
| Condensate at Mont Belvieu, Texas (US$/bbl) | **64.74** | 64.33 | **64.96** | 64.52 | 62.28 | 64.90 | 60.54 | 68.13 | 64.57 | 72.25 |
| Condensate at Mont Belvieu, Texas as a % of WTI | **82.2** | 85.8 | **80.6** | 83.8 | 79.5 | 78.9 | 82.1 | 89.5 | 78.1 | 78.9 |
| **Natural gas prices** | | | | | | | | | | |
| AECO (C$/mcf) | **2.00** | 3.09 | **1.29** | 2.72 | 2.51 | 2.83 | 2.67 | 3.51 | 5.57 | 4.54 |
| **Electric power prices** | | | | | | | | | | |
| Alberta power pool (C$/MWh) | **72.07** | 150.75 | **45.28** | 98.87 | 81.76 | 151.18 | 159.87 | 141.63 | 213.66 | 221.90 |
| **Foreign exchange rates** | | | | | | | | | | |
| C$ equivalent of 1 US$ – average | **1.3586** | 1.3475 | **1.3684** | 1.3488 | 1.3618 | 1.3410 | 1.3430 | 1.3520 | 1.3577 | 1.3059 |
| C$ equivalent of 1 US$ – period end | **1.3687** | 1.3238 | **1.3687** | 1.3533 | 1.3205 | 1.3537 | 1.3238 | 1.3528 | 1.3534 | 1.3700 |

### 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 and Canadian West Coast where it is typically sold at a discount to WTI reflecting supply/demand fundamentals for heavy sour oil in those regions.

WTI as well as WCS and AWB differentials improved period over period reflecting strong global demand for heavy crude and the unconstrained egress enabled by the TMX pipeline 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 three and six months ended June 30, 2024 compared to the same periods 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 52% and 35% in the three and six months ended June 30, 2024, respectively, relative to the comparable 2023 periods, primarily due to continued strong natural gas production in Alberta more than offsetting demand growth.

#### 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 72% and 52% in the three and six months ended June 30, 2024, compared to the same periods of 2023, reflecting increasing penetration of renewables, start-up of several new large scale gas fired generation units and substantially lower natural gas prices.

## 8. OTHER OPERATING RESULTS

#### General and Administrative

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions, except as indicated)* | **2024** | **2023** | **2024** | **2023** |
| General and administrative expense | **$ 18** | $ 15 | **$ 38** | $ 33 |
| General and administrative expense per barrel of production | **$ 1.98** | $ 1.85 | **$ 2.08** | $ 1.90 |
| Bitumen production – bbls/d | **100,531** | 85,974 | **102,309** | 96,349 |

General and administrative ("G&A") expense during the three and six months ended June 30, 2024 increased compared to the same periods of 2023, as expected, primarily due to higher costs associated with increased staff and salaries.

#### Depletion and Depreciation

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions, except as indicated)* | **2024** | **2023** | **2024** | **2023** |
| Depletion and depreciation expense | **$ 150** | $ 117 | **$ 309** | $ 260 |
| Depletion and depreciation expense per barrel of production | **$ 16.35** | $ 14.88 | **$ 16.57** | $ 14.87 |
| Bitumen production – bbls/d | **100,531** | 85,974 | **102,309** | 96,349 |

During the three and six months ended June 30, 2024, depletion and depreciation expense rose by $33 million and $49 million, respectively, compared to the same periods of 2023, mainly reflecting the impact of higher estimated future development costs on the per barrel depletion and depreciation rate and the increase in production.

### Stock-based Compensation

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Cash-settled expense (recovery) | **$ (3)** | $ (1) | **$ 8** | $ 17 |
| Equity-settled expense | **3** | 6 | **10** | 14 |
| Equity price risk management gain | **—** | — | **—** | (9) |
| Stock-based compensation expense | **$ —** | $ 5 | **$ 18** | $ 22 |

The decrease in stock-based compensation expense in the three and six months ended June 30, 2024, relative to the 2023 periods, mainly reflects fewer units outstanding.

The equity price risk management gain recognized in the first quarter of 2023 reflected the increase in the Corporation's share price during the first quarter of 2023. All equity price risk management contracts were fully realized as at March 31, 2023.

### Foreign Exchange Gain (Loss), Net

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Unrealized foreign exchange gain (loss) on: | | | | |
| Long-term debt | **$ (12)** | $ 31 | **$ (40)** | $ 31 |
| US$ denominated cash and cash equivalents | **—** | (2) | **6** | (3) |
| Unrealized net gain (loss) on foreign exchange | **(12)** | 29 | **(34)** | 28 |
| Realized gain (loss) on foreign exchange | **—** | 1 | **(1)** | 1 |
| Foreign exchange gain (loss), net | **$ (12)** | $ 30 | **$ (35)** | $ 29 |

| | | | | |
|---|---|---|---|---|
| C$ equivalent of 1 US$ | | | | |
| Beginning of period | **1.3533** | 1.3528 | **1.3205** | 1.3534 |
| End of period | **1.3687** | 1.3238 | **1.3687** | 1.3238 |

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 and six months ended June 30, 2024, the Canadian dollar weakened relative to the U.S. dollar by 1% and 4%, respectively, resulting in unrealized foreign exchange losses of $12 million and $34 million.

During the three and six months ended June 30, 2023, the Canadian dollar strengthened relative to the U.S. dollar by 2% in both periods resulting in unrealized foreign exchange gains of $29 million and $28 million, respectively.

### Net Finance Expense

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Interest expense on long-term debt | **$ 18** | $ 24 | **$ 37** | $ 49 |
| Interest expense on lease liabilities | **6** | 6 | **12** | 12 |
| Credit facility fees | **3** | 4 | **6** | 8 |
| Interest income | **(2)** | (2) | **(5)** | (4) |
| Net interest expense | **25** | 32 | **50** | 65 |
| Debt extinguishment expense | **—** | 2 | **7** | 6 |
| Accretion on provisions | **4** | 3 | **7** | 6 |
| Net finance expense | **$ 29** | $ 37 | **$ 64** | $ 77 |
| | | | | |
| Average effective interest rate | **6.1%** | 6.4% | **6.2%** | 6.4% |

Interest expense on long-term debt decreased during the three and six months ended June 30, 2024, compared to the same periods of 2023, primarily reflecting debt repaid in 2023 and 2024.

Debt extinguishment expense of $7 million was recognized on debt redemptions executed during the first half of 2024 and future redemptions forecast as at June 30, 2024. Refer to Note 10 of the interim consolidated financial statements for further details.

### Income Tax

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Earnings (loss) before income taxes | **$ 193** | $ 168 | **$ 330** | $ 278 |
| Effective tax rate | **30 %** | 19 % | **29 %** | 22 % |
| Income tax expense (recovery) | **$ 57** | $ 32 | **$ 96** | $ 61 |

As at June 30, 2024, the Corporation had approximately $4.1 billion of available Canadian tax pools, including $2.7 billion of non-capital losses and $0.2 billion of capital losses, and recognized a deferred income tax liability of $268 million.

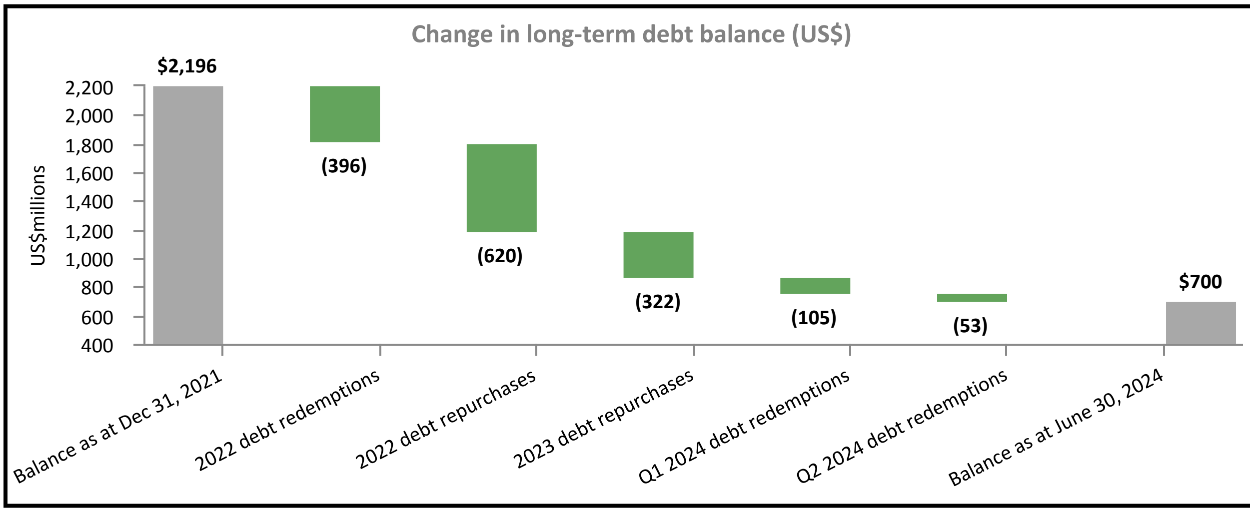
The effective tax rate differs from the Canadian statutory rate of 23% due to the tax effect of foreign exchange gains and losses on the Corporation's U.S. dollar denominated long-term debt, and the impact of an adjustment to the tax treatment of certain debt redemption costs.

## 9. LIQUIDITY AND CAPITAL RESOURCES

| *($millions)* | June 30, 2024 | December 31, 2023 |
|---|---|---|
| **Unsecured:** | | |
| 7.125% senior unsecured notes (June 30, 2024 - US$100 million; due 2027; December 31, 2023 - US$258.2 million) | **$ 137** | $ 341 |
| 5.875% senior unsecured notes (June 30, 2024 - US$600 million; due 2029; December 31, 2023 - US$600 million) | **821** | 792 |
| Debt redemption premium | **3** | — |
| Unamortized deferred debt discount and debt issue costs | **(7)** | (9) |
| Current and long-term debt | **954** | 1,124 |
| Cash and cash equivalents | **(86)** | (160) |
| Net debt - C$[1] | **$ 868** | $ 964 |
| Net debt - US$[1] | **$ 634** | $ 730 |

(1) *Net debt is reconciled to long-term debt in accordance with IFRS in Note 21 of the interim consolidated financial statements.*

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




The Corporation's cash and cash equivalents decreased to $86 million at June 30, 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$634 million at June 30, 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. Once this target is reached 100% of free cash flow will be returned to shareholders. The balance sheet strength and liquidity profile supports enhanced distributions to shareholders with a continued emphasis on share repurchases.

On July 25, 2024, the Corporation’s Board of Directors approved the initiation of a base dividend program and the Corporation intends to pay a cash dividend each quarter, subject to Board of Directors’ approval.

An inaugural cash dividend of $0.10 per share has been declared for payment on October 15, 2024 to shareholders of record on September 17, 2024. This dividend equates to an approximate 1.5% annual yield at MEG's current share price, a level that is positioned to grow through disciplined capital allocation.

Declaration of dividends is at the sole discretion of the Board of Directors and will continue to be evaluated on a quarterly basis. Future declarations will be dependent on, among other things, the prevailing business environment, MEG's financial and operating results and financial condition, the need for funds to finance ongoing operations or growth and other business conditions which the Corporation's Board of Directors considers relevant.

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.

In the second quarter of 2024, the Corporation repurchased for cancellation 2.2 million common shares under its NCIB program at a weighted-average price of $30.39 per share for a total cost of $68 million. During the first half of 2024, the Corporation returned $195 million to MEG shareholders through the repurchase and cancellation of 7.0 million shares at a weighted-average price of $28.05 per share.

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$100 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 June 30, 2024, the Corporation had $600 million of unutilized capacity under the revolving credit facility and, with $297 million of issued letters of credit, had $303 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Net cash provided by (used in): | | | | |
| Operating activities | **$ 267** | $ 244 | **$ 584** | $ 481 |
| Investing activities | **(119)** | (137) | **(238)** | (248) |
| Financing activities | **(147)** | (123) | **(426)** | (355) |
| Effect of exchange rate changes on cash and cash equivalents held in foreign currency | **—** | (3) | **6** | (4) |
| Change in cash and cash equivalents | **$ 1** | $ (19) | **$ (74)** | $ (126) |

### Cash Flow – Operating Activities

Net cash provided by operating activities during the three and six months ended June 30, 2024 increased $23 million and $103 million, respectively, compared to the same periods of 2023, primarily due to higher bitumen realization after net transportation and storage expense partially offset by increased royalties.

### Cash Flow – Investing Activities

Net cash used in investing activities decreased $18 million and $10 million during the three and six months ended June 30, 2024, respectively, compared to the same periods of 2023, reflecting reduced capital expenditures.

### Cash Flow – Financing Activities

Net cash used in financing activities increased $24 million and $71 million in the three and six months ended June 30, 2024, respectively, from the same periods of 2023, primarily reflecting free cash flow utilized 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Realized commodity risk management gain (loss) | **$ (8)** | $ (7) | **$ (12)** | $ (5) |
| Unrealized commodity risk management gain (loss) | **3** | (11) | **7** | (11) |
| **Commodity risk management gain (loss)** | **$ (5)** | $ (18) | **$ (5)** | $ (16) |

The Corporation had the following financial commodity risk management contracts relating to natural gas purchases outstanding at June 30, 2024:

| Natural Gas Purchase Contracts | Volumes (GJ/d) | Term | Average Price (C$/GJ) |
|---|---|---|---|
| AECO Fixed Price | 30,000 | Jul 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 June 30, 2024:

| Natural Gas Purchase Contracts | Volumes (GJ/d) | Term | Average Price (C$/GJ) |
|---|---|---|---|
| AECO Fixed Price | 5,000 | Jul 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | 2024 | 2023 | 2024 | 2023[(1)] |
| Unrealized equity price risk management loss | $ — | $ — | $ — | $ 78 |
| Realized equity price risk management gain | — | — | — | (87) |
| Equity price risk management gain | $ — | $ — | $ — | $ (9) |

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

## 11. SHARES OUTSTANDING

At June 30, 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 | (6,964) |
| Common shares outstanding at June 30, 2024 | **270,142** |
| Convertible securities: | |
| Stock options(1) | **2** |
| Equity-settled RSUs and PSUs | **2,206** |

*(1) All outstanding stock options were exercisable at June 30, 2024.*

At July 24, 2024, the Corporation had 269.5 million common shares outstanding, two thousand stock options outstanding and exercisable and 2.2 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 June 30, 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) | $ 251 | $ 496 | $ 494 | $ 496 | $ 501 | $ 5,172 | $ 7,410 |
| Diluent purchases(2)(3) | 192 | 46 | 5 | — | — | — | 243 |
| Other operating commitments | 9 | 18 | 18 | 9 | 9 | 59 | 122 |
| Variable office lease costs | 2 | 4 | 4 | 5 | 5 | 13 | 33 |
| Capital commitments | 62 | — | — | — | — | — | 62 |
| **Total Commitments** | 516 | 564 | 521 | 510 | 515 | 5,244 | 7,870 |
| **Other Obligations:** | | | | | | | |
| Lease liabilities | 18 | 39 | 37 | 37 | 37 | 413 | 581 |
| Long-term debt(4) | — | — | — | 137 | — | 821 | 958 |
| Interest on long-term debt(4) | 29 | 58 | 58 | 49 | 48 | 6 | 248 |
| Decommissioning obligation(5) | 3 | 9 | 9 | 9 | 9 | 830 | 869 |
| **Total Commitments and Obligations** | **$ 566** | **$ 670** | **$ 625** | **$ 742** | **$ 609** | **$ 7,314** | **$ 10,526** |

*(1) This represents transportation and storage commitments from 2024 to 2048. Excludes finance leases recognized on the consolidated balance sheet.*

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

*(3) Subsequent to June 30, 2024, the Corporation executed a 5-year diluent supply commitment totaling $312 million.*

*(4) This represents the scheduled principal repayments of the senior unsecured notes and associated interest payments based on interest and foreign exchange rates in effect on June 30, 2024.*

*(5) 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Funds flow from operating activities | **$ 354** | $ 278 | **$ 683** | $ 626 |
| Adjustments: | | | | |
| Impact of cash-settled SBC units subject to equity price risk management | **—** | — | **—** | 13 |
| Realized equity price risk management gain | **—** | — | **—** | (87) |
| Adjusted funds flow | **354** | 278 | **683** | 552 |
| Capital expenditures | **(123)** | (149) | **(235)** | (262) |
| Free cash flow | **$ 231** | $ 129 | **$ 448** | $ 290 |

### Net Debt

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

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

| As at | June 30, 2024 | December 31, 2023 |
|---|---|---|
| Long-term debt | $ 954 | $ 1,124 |
| Cash and cash equivalents | (86) | (160) |
| Net debt - C$ | $ 868 | $ 964 |
| Net debt - US$ | $ 634 | $ 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | 2024 | 2023 | 2024 | 2023 |
| Revenues | $ 1,373 | $ 1,291 | $ 2,737 | $ 2,771 |
| Diluent expense | (412) | (363) | (868) | (861) |
| Transportation and storage expense | (147) | (152) | (277) | (295) |
| Purchased product | (341) | (373) | (645) | (787) |
| Operating expenses | (66) | (73) | (152) | (172) |
| Realized gain (loss) on commodity risk management | (8) | (7) | (12) | (5) |
| Cash operating netback | $ 399 | $ 323 | $ 783 | $ 651 |

### 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 June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2024 | | 2023 | | 2024 | | 2023 | |
| *($millions, except as indicated)* | | $/bbl | | $/bbl | | $/bbl | | $/bbl |
| Revenues | **$ 1,373** | | $ 1,291 | | **$ 2,737** | | $ 2,771 | |
| Power and transportation revenue | **(10)** | | (24) | | **(36)** | | (65) | |
| Royalties | **162** | | 58 | | **290** | | 89 | |
| Petroleum revenue | **1,525** | | 1,325 | | **2,991** | | 2,795 | |
| Purchased product | **(341)** | | (373) | | **(645)** | | (787) | |
| Blend sales | **1,184** | **$ 98.02** | 952 | $ 87.81 | **2,346** | **$ 90.30** | 2,008 | $ 81.22 |
| Diluent expense | **(412)** | **(6.91)** | (363) | (10.27) | **(868)** | **(8.50)** | (861) | (14.48) |
| Bitumen realization | **$ 772** | **$ 91.11** | $ 589 | $ 77.54 | **$ 1,478** | **$ 81.80** | $ 1,147 | $ 66.74 |

## 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 June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2024 | | 2023 | | 2024 | | 2023 | |
| *($millions, except as indicated)* | | $/bbl | | $/bbl | | $/bbl | | $/bbl |
| Transportation and storage expense | **$ (147)** | **$(17.34)** | $ (152) | $(20.01) | **$ (277)** | **$(15.32)** | $ (295) | $(17.15) |
| Power and transportation revenue | **$ 10** | | $ 24 | | **$ 36** | | $ 65 | |
| Less power revenue | **(10)** | | (23) | | **(35)** | | (63) | |
| Transportation revenue | **$ —** | **$ 0.07** | $ 1 | $ 0.11 | **$ 1** | **$ 0.07** | $ 2 | $ 0.10 |
| Net transportation and storage expense | **$ (147)** | **$(17.27)** | $ (151) | $(19.90) | **$ (276)** | **$(15.25)** | $ (293) | $(17.05) |

## 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 June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2024 | | 2023 | | 2024 | | 2023 | |
| *($millions, except as indicated)* | | $/bbl | | $/bbl | | $/bbl | | $/bbl |
| Bitumen realization[1] | **$ 772** | **$ 91.11** | $ 589 | $ 77.54 | **$ 1,478** | **$ 81.80** | $ 1,147 | $ 66.74 |
| Net transportation and storage expense[1] | **(147)** | **(17.27)** | (151) | (19.90) | **(276)** | **(15.25)** | (293) | (17.05) |
| Bitumen realization after net transportation and storage expense | **$ 625** | **$ 73.84** | $ 438 | $ 57.64 | **$ 1,202** | **$ 66.55** | $ 854 | $ 49.69 |

*(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 June 30 | | | | Six months ended June 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | 2024 | | 2023 | | 2024 | | 2023 | |
| *($millions, except as indicated)* | | $/bbl | | $/bbl | | $/bbl | | $/bbl |
| Non-energy operating costs | **$ (48)** | **$ (5.63)** | $ (43) | $ (5.66) | **$ (98)** | **$ (5.39)** | $ (89) | $ (5.17) |
| Energy operating costs | **(18)** | **(2.13)** | (30) | (3.92) | **(54)** | **(2.99)** | (83) | (4.84) |
| Operating expenses | **$ (66)** | **$ (7.76)** | $ (73) | $ (9.58) | **$ (152)** | **$ (8.38)** | $ (172) | $(10.01) |
| Power and transportation revenue | **$ 10** | | $ 24 | | **$ 36** | | $ 65 | |
| Less transportation revenue | **—** | | (1) | | **(1)** | | (2) | |
| Power revenue | **$ 10** | **$ 1.14** | $ 23 | $ 2.95 | **$ 35** | **$ 1.89** | $ 63 | $ 3.66 |
| Operating expenses net of power revenue | **$ (56)** | **$ (6.62)** | $ (50) | $ (6.63) | **$ (117)** | **$ (6.49)** | $ (109) | $ (6.35) |
| Energy operating costs net of power revenue | **$ (8)** | **$ (0.99)** | $ (7) | $ (0.97) | **$ (19)** | **$ (1.10)** | $ (20) | $ (1.18) |

### 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 June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| *($millions)* | **2024** | **2023** | **2024** | **2023** |
| Bitumen realization | **$ 772** | $ 589 | **$ 1,478** | $ 1,147 |
| Transportation and storage expense | **(147)** | (152) | **(277)** | (295) |
| Transportation revenue | **—** | 1 | **1** | 2 |
| Bitumen realization after net transportation and storage expense | **$ 625** | $ 438 | **$ 1,202** | $ 854 |
| Royalties | **$ 162** | $ 58 | **$ 290** | $ 89 |
| Effective royalty rate | **25.9 %** | 13.2 % | **24.1 %** | 10.4 % |

## 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 intention to pay a cash dividend each quarter subject to Board of Directors approval and the Corporation's expectation that this dividend is positioned to grow through disciplined capital allocation; the Corporation’s marketing strategy and marketing asset optimization strategy; the Corporation's expectation 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; the Corporation's expectation that it will benefit from its pipeline transportation commitments as western Canadian production grows and egress fills; 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 possibility 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 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 economic recovery of oil. MEG transports and sells its thermal oil (known as AWB) to customers throughout North America and internationally. MEG is a member of the Pathways Alliance, a group of Canada's largest oil sands producers. 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** | **Q2** | **Q1** | **Q4** | **Q3** | **Q2** | **Q1** | **Q4** | **Q3** |
| **FINANCIAL** *($millions unless specified)* | | | | | | | | |
| Net earnings (loss) | **136** | 98 | 103 | 249 | 136 | 81 | 159 | 156 |
| Per share, diluted | **0.50** | 0.36 | 0.37 | 0.86 | 0.47 | 0.28 | 0.53 | 0.51 |
| Funds flow from operating activities | **354** | 329 | 358 | 492 | 278 | 348 | 383 | 501 |
| Per share, diluted | **1.30** | 1.19 | 1.27 | 1.71 | 0.96 | 1.19 | 1.28 | 1.63 |
| Adjusted funds flow(1) | **354** | 329 | 358 | 492 | 278 | 274 | 401 | 496 |
| Per share, diluted(1) | **1.30** | 1.19 | 1.27 | 1.71 | 0.96 | 0.94 | 1.34 | 1.61 |
| Capital expenditures | **123** | 112 | 104 | 83 | 149 | 113 | 106 | 78 |
| Free cash flow(1) | **231** | 217 | 254 | 409 | 129 | 161 | 295 | 418 |
| Working capital | **344** | 226 | 278 | 495 | 231 | 219 | 289 | 395 |
| Net debt - C$(1) | **868** | 930 | 964 | 1,198 | 1,316 | 1,381 | 1,389 | 1,634 |
| Net debt - US$(1) | **634** | 687 | 730 | 885 | 994 | 1,020 | 1,026 | 1,193 |
| Shareholders' equity | **4,580** | 4,511 | 4,527 | 4,641 | 4,441 | 4,370 | 4,383 | 4,418 |
| **BUSINESS ENVIRONMENT** | | | | | | | | |
| **Average Benchmark Commodity Prices:** | | | | | | | | |
| WTI (US$/bbl) | **80.57** | 76.96 | 78.32 | 82.26 | 73.78 | 76.13 | 82.65 | 91.55 |
| Differential – WTI:WCS – Edmonton (US$/bbl) | **(13.61)** | (19.31) | (21.89) | (12.91) | (15.16) | (24.88) | (25.89) | (19.86) |
| AWB – Edmonton (US$/bbl) | **65.99** | 55.96 | 54.53 | 67.88 | 56.41 | 48.50 | 53.51 | 68.75 |
| Mainline heavy apportionment | **5 %** | 28 % | 21 % | 1 % | 1 % | 12 % | 5 % | 3 % |
| C$ equivalent of 1US$ – average | **1.3684** | 1.3488 | 1.3618 | 1.3410 | 1.3430 | 1.3520 | 1.3577 | 1.3059 |
| Natural gas – AECO ($/mcf) | **1.29** | 2.72 | 2.51 | 2.83 | 2.67 | 3.51 | 5.57 | 4.54 |
| **OPERATIONAL** **($/bbl unless specified)** | | | | | | | | |
| Blend sales, net of purchased product – bbls/d | **132,812** | 152,844 | 158,850 | 140,002 | 119,187 | 154,197 | 160,163 | 131,327 |
| Diluent usage – bbls/d | **(39,672)** | (47,310) | (46,216) | (38,377) | (35,656) | (47,717) | (46,581) | (35,568) |
| Bitumen sales – bbls/d | **93,140** | 105,534 | 112,634 | 101,625 | 83,531 | 106,480 | 113,582 | 95,759 |
| Bitumen production – bbls/d | **100,531** | 104,088 | 109,112 | 103,726 | 85,974 | 106,840 | 110,805 | 101,983 |
| Steam-oil ratio (SOR) | **2.44** | 2.37 | 2.28 | 2.28 | 2.25 | 2.25 | 2.22 | 2.39 |
| Blend sales(2) | **98.02** | 83.58 | 87.33 | 101.53 | 87.81 | 76.07 | 83.28 | 99.96 |
| Diluent expense | **(6.91)** | (10.00) | (9.58) | (0.06) | (10.27) | (17.89) | (14.12) | (9.63) |
| Bitumen realization(2) | **91.11** | 73.58 | 77.75 | 101.47 | 77.54 | 58.18 | 69.16 | 90.33 |
| Net transportation and storage expense(2) | **(17.27)** | (13.48) | (14.23) | (16.72) | (19.90) | (14.78) | (14.41) | (15.58) |
| Bitumen realization after net transportation and storage expense(2) | **73.84** | 60.10 | 63.52 | 84.75 | 57.64 | 43.40 | 54.75 | 74.75 |
| Royalties | **(19.12)** | (13.35) | (17.92) | (19.45) | (7.69) | (3.18) | (5.15) | (7.47) |
| Non-energy operating costs(3) | **(5.63)** | (5.18) | (4.64) | (5.15) | (5.66) | (4.77) | (4.34) | (4.49) |
| Energy operating costs(3) | **(2.13)** | (3.74) | (3.25) | (3.42) | (3.92) | (5.57) | (6.71) | (6.12) |
| Power revenue | **1.14** | 2.55 | 1.79 | 3.46 | 2.95 | 4.21 | 5.22 | 5.16 |
| Realized gain (loss) on commodity risk management | **(0.96)** | (0.39) | (0.85) | (1.55) | (0.94) | 0.23 | 0.12 | 0.80 |
| Cash operating netback(2) | **47.14** | 39.99 | 38.65 | 58.64 | 42.38 | 34.32 | 43.89 | 62.63 |
| Revenues | **1,373** | 1,364 | 1,444 | 1,438 | 1,291 | 1,480 | 1,445 | 1,571 |
| Power sales price (C$/MWh) | **45.57** | 102.53 | 81.66 | 156.04 | 150.19 | 162.90 | 219.81 | 217.25 |
| Power sales (MW/h) | **100** | 113 | 108 | 97 | 71 | 118 | 116 | 98 |
| Average cost of diluent ($/bbl of diluent) | **114.25** | 105.89 | 110.65 | 101.68 | 111.85 | 116.01 | 117.72 | 125.91 |
| Average cost of diluent as a % of WTI | **104 %** | 102 % | 104 % | 92 % | 113 % | 113 % | 105 % | 105 % |
| Depletion and depreciation rate per bbl of production | **16.35** | 16.79 | 19.01 | 15.28 | 14.88 | 14.86 | 15.84 | 14.30 |
| General and administrative expense per bbl of production | **1.98** | 2.18 | 1.89 | 1.73 | 1.85 | 1.94 | 1.62 | 1.72 |
| **COMMON SHARES** | | | | | | | | |
| Shares outstanding, end of period (000) | **270,142** | 272,376 | 274,642 | 283,290 | 285,566 | 288,614 | 291,081 | 301,649 |
| Common share price ($) - close (end of period) | **29.27** | 31.10 | 23.67 | 26.43 | 21.00 | 21.71 | 18.85 | 15.46 |

*(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$91.55/bbl;
- variability in WTI:WCS differential at Edmonton which ranged from a quarterly average of US$12.91/bbl to US$25.89/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 and Canadian West Coast markets, including the impact of the TMX start-up in the second quarter of 2024;
- 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$/bbl) | **(18.71)** | (18.27) | (13.04) | (12.60) | (12.76) | (26.31) | (11.98) |
| AWB – Edmonton (US$/bbl) | **56.83** | 73.59 | 53.20 | 25.08 | 42.08 | 34.78 | 36.86 |
| 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.*