



## MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three months ended March 31, 2025 was approved by the Corporation's Board of Directors on May 6, 2025. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three months ended March 31, 2025, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2024, the 2024 annual MD&A and the 2024 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 Accounting Standards 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 Accounting Standards. Please refer to section 11 "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, 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:** funds from operations, free cash flow, and net debt.

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## 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:

	2025	2024			
<i>(\$millions, except as indicated)</i>	Q1	Q4	Q3	Q2	Q1
<b>Operational results:</b>					
Bitumen production - bbls/d	103,224	100,139	103,298	100,531	104,088
Per share, diluted	0.04	0.03	0.04	0.03	0.03
Steam-oil ratio	2.28	2.40	2.36	2.44	2.37
Bitumen sales - bbls/d	102,126	100,821	105,255	93,140	105,534
<b>Business environment:</b>					
WTI - US\$/bbl	71.42	70.27	75.09	80.57	76.96
Differential - WTI:WCS - Edmonton - US\$/bbl	(12.67)	(12.56)	(13.55)	(13.61)	(19.31)
AWB - Edmonton - US\$/bbl	57.77	56.82	60.62	65.99	55.96
C\$ equivalent of 1 US\$ – average	1.4350	1.3991	1.3636	1.3684	1.3488
<b>Financial results:</b>					
Bitumen realization after net transportation and storage expense <sup>(1)</sup> - \$/bbl	65.98	62.62	65.61	73.84	60.10
Non-energy operating costs <sup>(2)</sup> - \$/bbl	5.84	5.61	5.18	5.63	5.18
Energy operating costs net of power revenue <sup>(1)</sup> - \$/bbl	2.06	0.90	0.64	0.99	1.19
Operating expenses net of power revenue <sup>(1)</sup> - \$/bbl	7.90	6.51	5.82	6.62	6.37
Cash operating netback <sup>(1)</sup> - \$/bbl	46.30	41.09	41.35	47.14	39.99
Royalties	108	132	169	162	128
Funds from operations <sup>(3)</sup>	380	340	362	354	329
Per share, diluted	1.47	1.29	1.34	1.30	1.19
Capital expenditures	157	172	141	123	112
Free cash flow <sup>(3)</sup>	223	168	221	231	217
Per share, diluted	0.86	0.64	0.82	0.85	0.78
Weighted average common shares outstanding - diluted	258	263	269	272	276
Debt repayments - US\$	—	—	100	53	105
Share repurchases - C\$	159	151	108	68	127
Dividends paid - C\$	26	27	—	—	—
Revenues	1,162	1,147	1,265	1,373	1,364
Net earnings	211	106	167	136	98
Per share, diluted	0.82	0.40	0.62	0.50	0.36

(1) Non-GAAP financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.

(2) Supplementary financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.

(3) Capital management measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.

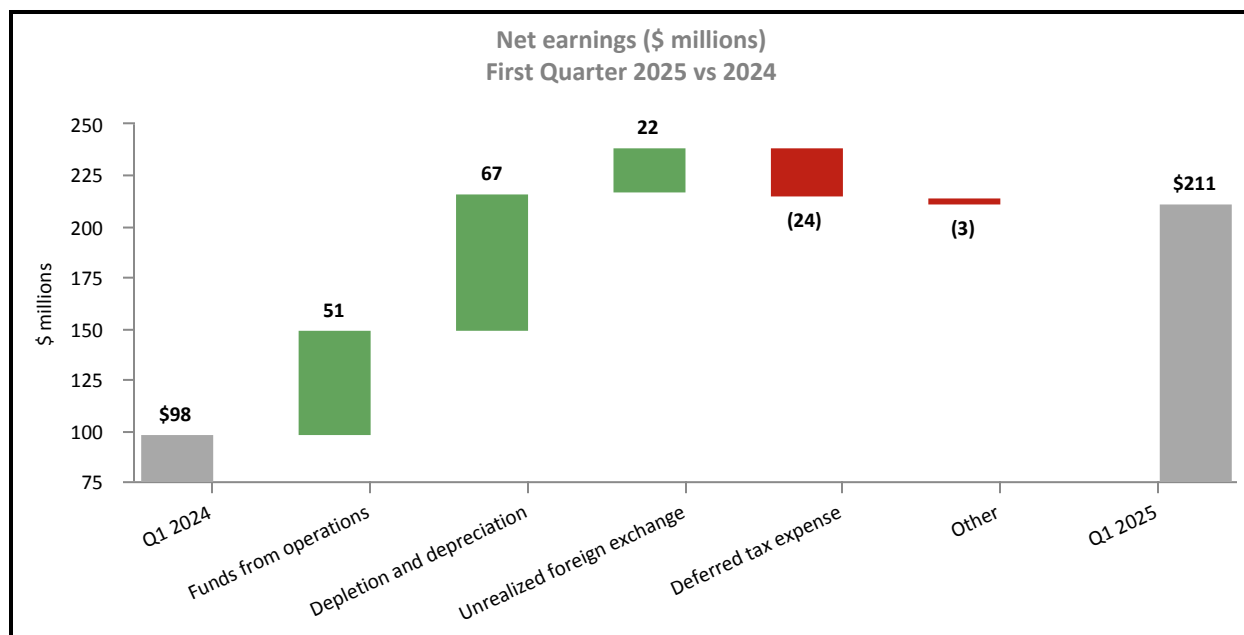
The Corporation generated free cash flow ("FCF") of \$223 million in the first quarter of 2025, which was used to return \$159 million to shareholders through the repurchase of 6.7 million shares, or 3% of total shares outstanding at December 31, 2024, and pay a quarterly cash dividend of \$26 million.

Funds from operations ("FFO") during the first quarter of 2025 increased 16% to \$380 million from \$329 million in the same period of 2024. The increase mainly reflects a higher blend sales price partially offset by lower blend sales volumes and higher net transportation and storage expense. On a diluted per share basis, FFO increased 24% to \$1.47 in the first quarter of 2025 from \$1.19 in the comparative 2024 period reflecting the combined impact of increased FFO and share repurchases.

Average bitumen production volumes in the first quarter of 2025 were 103,224 barrels per day, at a steam-oil ratio ("SOR") of 2.28, compared to 104,088 barrels per day, at an SOR of 2.37, in the first quarter of 2024.

Capital expenditures increased to \$157 million from \$112 million in the first quarters of 2025 and 2024, respectively. The increase primarily reflects the planned investment in the facility expansion project ("FEP") and field and facility infrastructure costs.

## 2. NET EARNINGS



Net earnings increased to \$211 million in the first quarter of 2025, from \$98 million in the same period of 2024, driven by higher FFO, lower depletion and depreciation expense and a reduced unrealized foreign exchange loss partially offset by higher deferred income tax expense.

## 3. REVENUES

	Three months ended March 31	
(\$millions)	2025	2024
Sales from:		
Production	\$ 1,229	\$ 1,153
Purchased product <sup>(1)</sup>	30	313
Petroleum revenue	\$ 1,259	\$ 1,466
Royalties	(108)	(128)
Petroleum revenue, net of royalties	\$ 1,151	\$ 1,338
Power revenue	\$ 10	\$ 25
Transportation revenue	1	1
Power and transportation revenue	\$ 11	\$ 26
Revenues	\$ 1,162	\$ 1,364

(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 March 31, 2025, petroleum revenue, net of royalties decreased to \$1.2 billion from \$1.3 billion in the same period of 2024. The reduction in first quarter 2025 sales from purchased product reflects lower marketing asset optimization activity as a result of improved pipeline egress, while sales from production rose due to a higher realized blend sales price partially offset by lower blend sales volumes. Royalties declined due to lower annual crude oil price estimates.

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.

#### 4. RESULTS OF OPERATIONS

##### Bitumen Production and Steam-Oil Ratio

	Three months ended March 31	
	2025	2024
Bitumen production – bbls/d	103,224	104,088
Bitumen production per share - diluted	0.04	0.03
Steam-oil ratio (SOR)	2.28	2.37

##### Bitumen Production

Bitumen production averaged 103,224 barrels per day during the three months ended March 31, 2025 compared to 104,088 barrels per day in the same period of 2024. First quarter of 2025 production reflects increased unplanned maintenance activities relative to the same period of 2024.

On a diluted per share basis, bitumen production increased to 0.04 barrels in the first quarter of 2025 from 0.03 barrels in the same period of 2024 reflecting share repurchases.

##### Steam-Oil Ratio ("SOR")

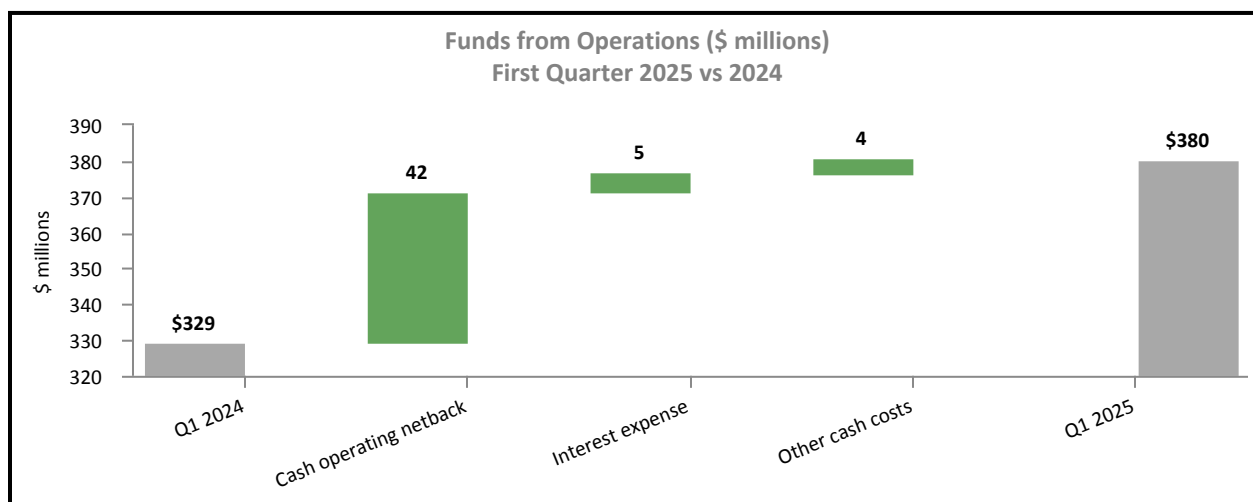
The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is SOR, which is an efficiency indicator that measures the amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR decreased approximately 4% to 2.28 in the first quarter of 2025 from 2.37 in the same period of 2024. This performance reflects improved reservoir quality and optimized design of recent wells.

##### Funds from Operations ("FFO") and Free Cash Flow ("FCF")

FFO and FCF are capital management measures defined in the Corporation's consolidated financial statements and both are presented to assist management and investors in analyzing operating performance and cash flow generating ability. FFO is calculated as net cash provided by (used in) operating activities before the net change in non-cash working capital items. FCF also assists management and investors in analyzing performance by the Corporation as a measure of financial liquidity and the capacity of the business to return capital to shareholders. FCF is calculated as FFO less capital expenditures.

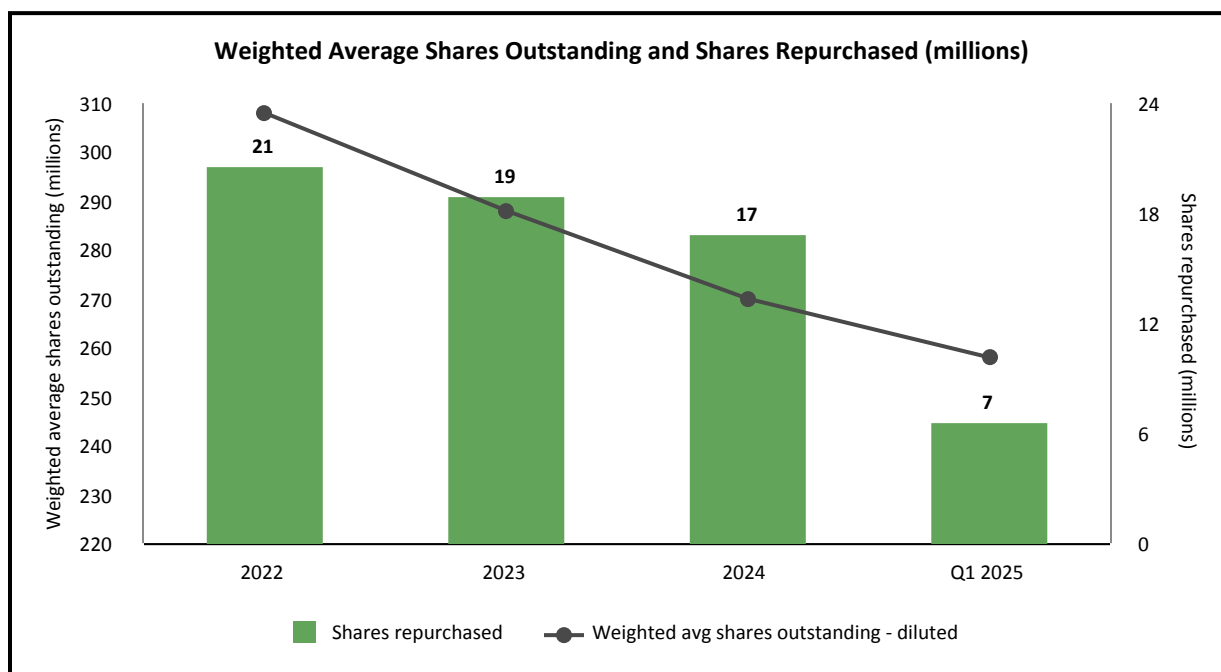
		Three months ended March 31	
(\$millions, except as indicated)		2025	2024
Funds from operations <sup>(1)</sup>	\$	380	\$ 329
Funds from operations per share - diluted	\$	1.47	\$ 1.19
Free cash flow <sup>(1)</sup>	\$	223	\$ 217
Free cash flow per share - diluted	\$	0.86	\$ 0.78
Weighted average shares outstanding - diluted		258	276

(1) Capital management measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.



FFO increased in the first quarter of 2025, compared to the same period of 2024, driven mainly by a higher cash operating netback and a lower interest expense due to reduced debt levels.

On a diluted per share basis, FFO increased to \$1.47 per share in the first quarter of 2025 from \$1.19 per share in the comparative 2024 period, reflecting the combined impact of increased FFO and share repurchases.



## CASH OPERATING NETBACK

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

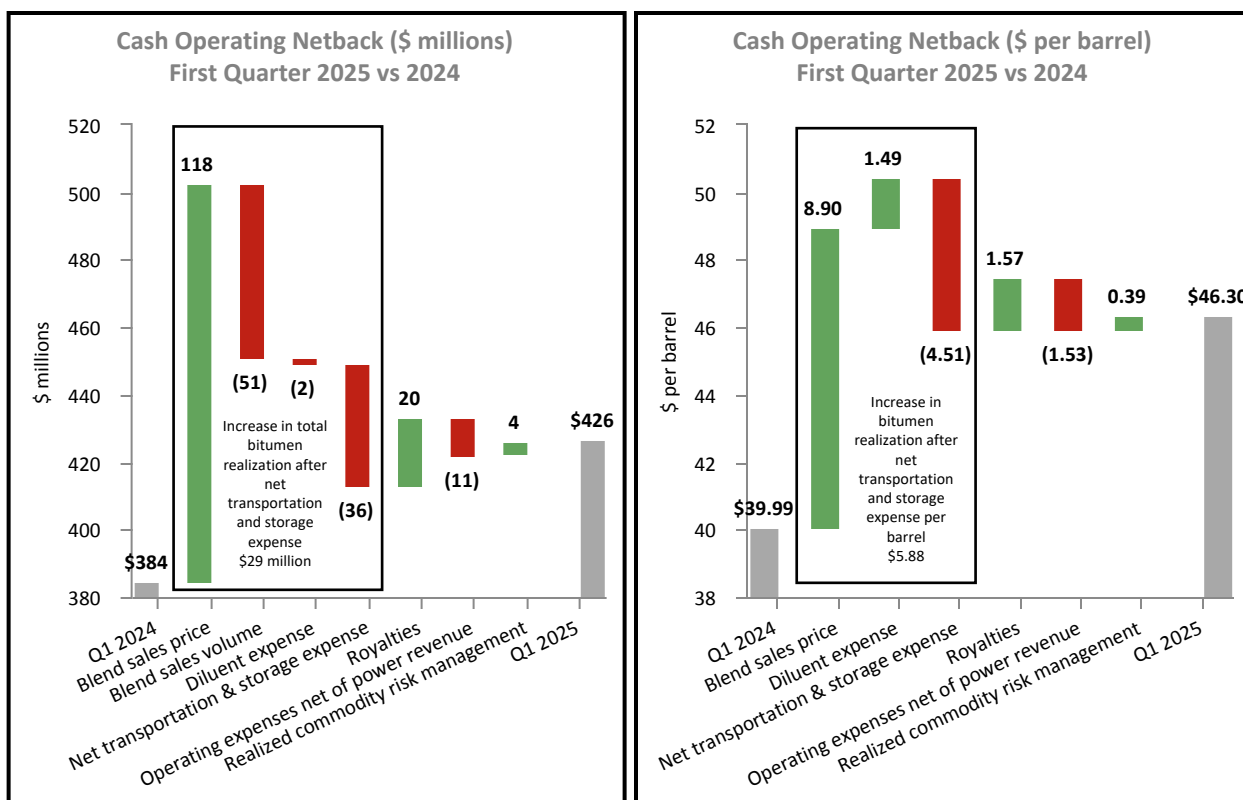
Three months ended March 31				
	2025		2024	
<i>(\$millions, except as indicated)</i>	<i>\$/bbl</i>		<i>\$/bbl</i>	
Sales from production	\$	1,229	\$	1,153
Sales from purchased product <sup>(1)</sup>		30		313
Petroleum revenue	\$	1,259	\$	1,466
Purchased product <sup>(1)</sup>		(30)		(304)
Blend sales <sup>(2)(3)</sup>	\$	1,229	\$	1,162
Diluent expense		(458)		(456)
Bitumen realization <sup>(3)</sup>	\$	771	\$	706
Net transportation and storage expense <sup>(3)(4)</sup>		(165)		(129)
Bitumen realization after net transportation and storage expense <sup>(3)</sup>	\$	606	\$	577
Royalties		(108)		(128)
Operating expenses net of power revenue <sup>(3)</sup>		(72)		(61)
Realized loss on commodity risk management		—		(4)
Cash operating netback <sup>(3)</sup>	\$	426	\$	384
Bitumen sales volumes - bbls/d		102,126		105,534

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

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

(3) Non-GAAP financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.

(4) Net transportation and storage expense includes costs associated with moving and storing AWB to optimize the timing of delivery.



During the three months ended March 31, 2025, cash operating netback increased to \$426 million from \$384 million in the same period of 2024, reflecting a higher blend sales price and lower royalties, partially offset by lower blend sales volumes, higher net transportation and storage expense and increased operating expenses net of power revenue.

On a per barrel basis, cash operating netback rose to \$46.30 per barrel in the first quarter of 2025 from \$39.99 in the same period of 2024, mainly reflecting an increased bitumen realization after net transportation and storage expense and lower royalties partially offset by higher operating expenses net of power revenue.

#### 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 at the ultimate sales location 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 price and the WTI:AWB differential.

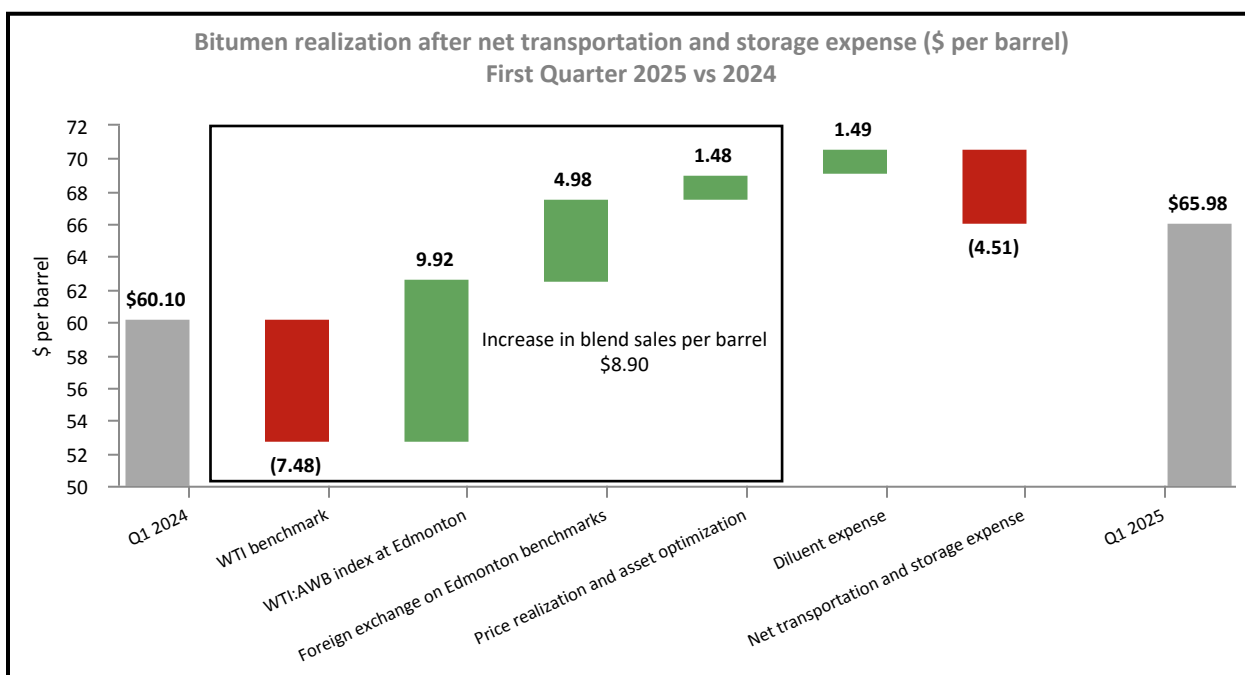


	Three months ended March 31			
	2025		2024	
(\$millions, except as indicated)	\$/bbl		\$/bbl	
Sales from production	\$	1,229	\$	1,153
Sales from purchased product <sup>(1)</sup>		30		313
Petroleum revenue	\$	1,259	\$	1,466
Purchased product <sup>(1)</sup>		(30)		(304)
Blend sales <sup>(2)(3)</sup>	\$	1,229	\$	1,162
Diluent expense		(458)		(456)
Bitumen realization <sup>(3)</sup>	\$	771	\$	706
Net transportation and storage expense <sup>(3)</sup>		(165)		(129)
Bitumen realization after net transportation and storage expense	\$	606	\$	577
Bitumen sales volumes - bbls/d		102,126		105,534

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

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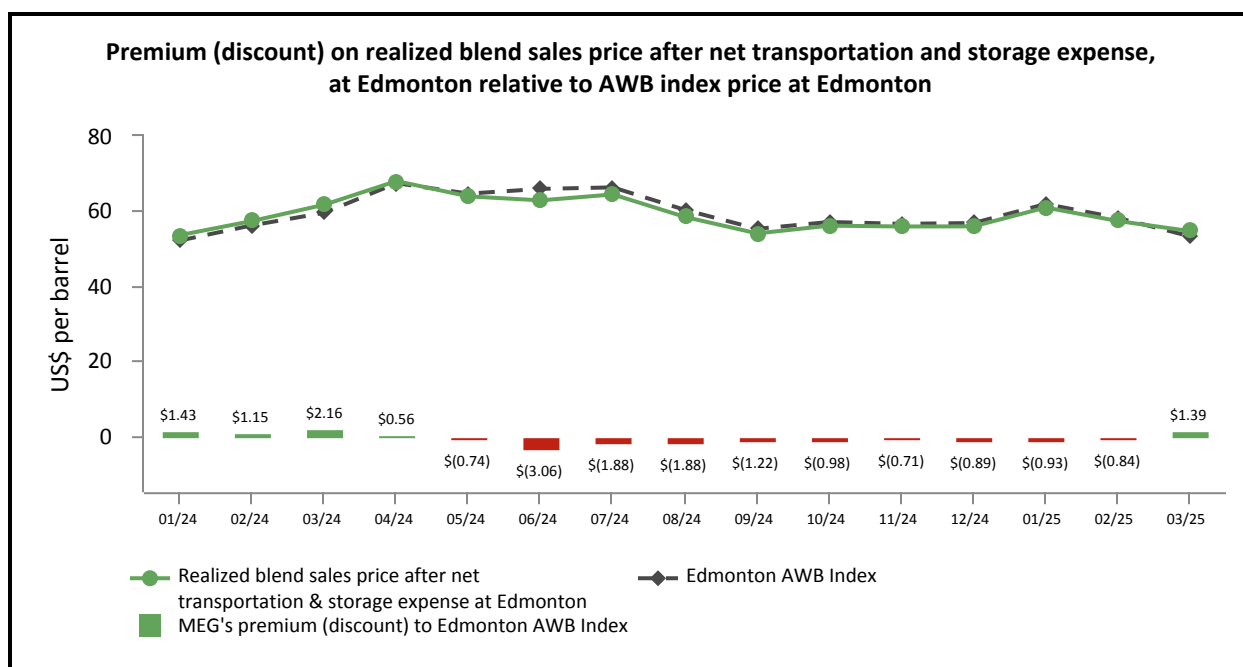
Bitumen realization after net transportation and storage expense increased 10%, to \$65.98 per barrel, in the three months ended March 31, 2025, from \$60.10 per barrel in the same period of 2024. The benefits from narrower WTI:AWB differentials, the positive impact of a weaker Canadian dollar, higher price realization associated with diverse market access, and lower diluent expense were partially offset by a lower average WTI price and higher net transportation and storage expense.

Diluent expense per barrel in the three months ended March 31, 2025 decreased to \$8.51 from \$10.00 in the same period of 2024, reflecting narrower WTI:AWB differentials partially offset by a higher average condensate price relative to WTI. As a result, the Corporation recovered 83% of diluent costs through blend sales in the three months ended March 31, 2025 compared to 79% in the same period of 2024.

	Three months ended March 31			
	2025		2024	
<i>(\$millions, except as indicated)</i>				
	\$/bbl		\$/bbl	
Transportation and storage expense	\$	(166)	\$ (18.07)	\$ (130) \$ (13.55)
Transportation revenue		1	0.08	1 0.07
Net transportation and storage expense	\$	(165)	\$ (17.99)	\$ (129) \$ (13.48)
Bitumen sales volumes - bbls/d	102,126		105,534	

Net transportation and storage expense in the three months ended March 31, 2025, on a total and per barrel basis, rose relative to the same period of 2024 primarily reflecting higher volumes shipped to the USGC as a result of lower pipeline apportionment and new tolls on volumes transported to the west coast of Canada on TMX.

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.



In the first quarter of 2025, the Corporation's overall average realized blend sales price after net transportation and storage expense received a discount of US\$0.08 per barrel compared to the Edmonton AWB index.

Since 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 transportation 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 Corporation's Christina Lake project reached payout in 2023.

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. Royalties are calculated in respect of a calendar year with monthly installments paid based on annual estimates allocated by revenue.

	Three months ended March 31	
(\$millions)	2025	2024
Royalties	\$ 108	\$ 128
Royalty rate	35.5 %	35.3 %

Royalties in the first quarter of 2025 decreased 15%, compared to the same period of 2024. Royalties declined primarily due to lower annual forecasted net revenues reflecting the impact of lower crude oil price estimates for 2025 and a higher capital expenditures forecast.

#### Operating Expenses net of Power Revenue

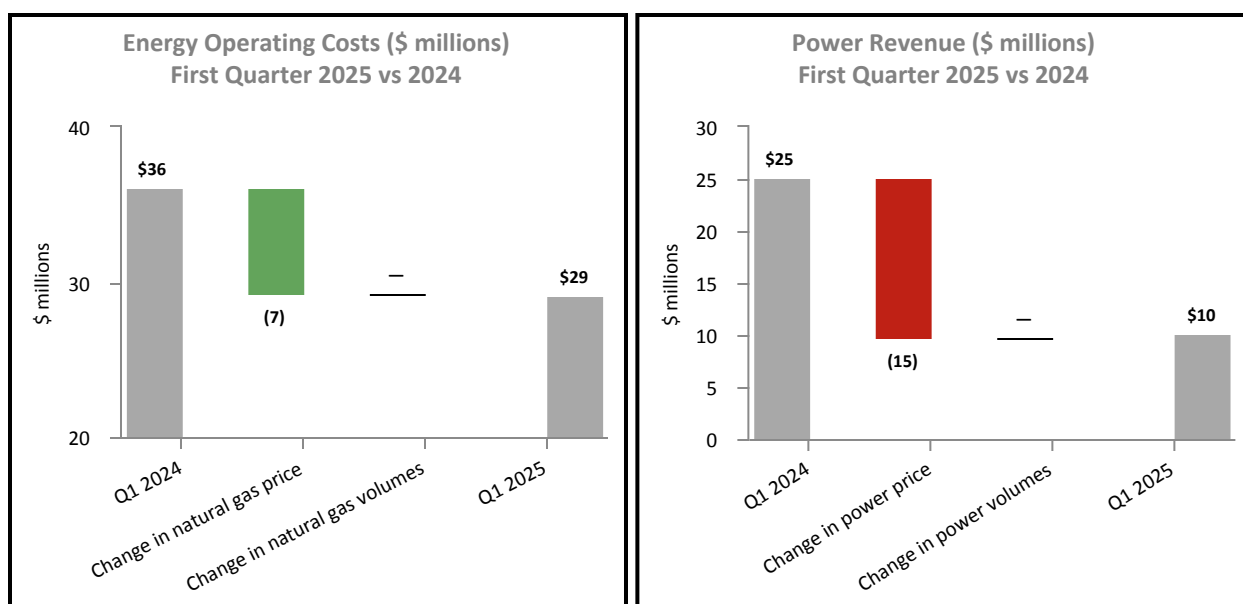
Operating expenses net of power revenue are comprised of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-oriented operating activities and energy operating costs reflect the cost of natural gas used to generate steam and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

	Three months ended March 31			
	2025		2024	
(\$millions, except as indicated)	\$/bbl		\$/bbl	
Non-energy operating costs <sup>(1)</sup>	\$ (53)	\$ (5.84)	\$ (50)	\$ (5.18)
Energy operating costs <sup>(1)</sup>	(29)	(3.12)	(36)	(3.74)
Operating expenses	(82)	(8.96)	(86)	(8.92)
Power revenue	10	1.06	25	2.55
Operating expenses net of power revenue <sup>(2)</sup>	\$ (72)	\$ (7.90)	\$ (61)	\$ (6.37)
Energy operating costs net of power revenue <sup>(2)</sup>	\$ (19)	\$ (2.06)	\$ (11)	\$ (1.19)
Average delivered natural gas price (C\$/mcf)	\$ 2.44		\$ 3.03	
Average realized power sales price (C\$/Mwh)	\$ 41.31		\$ 102.53	

(1) Supplementary financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.

(2) Non-GAAP financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.

Total non-energy operating costs during the first quarter of 2025 increased \$3 million, to \$53 million, from the same period of 2024, primarily reflecting expected increases in process treating costs and services as a result of new well pads. Lower bitumen sales volumes during the first quarter of 2025, compared to the same period of 2024, further contributed to the increase on a per barrel basis.



Energy operating costs in the first quarter of 2025, on a total and per barrel basis, decreased compared to the same period of 2024 reflecting a weaker AECO natural gas price.

Power revenue in the first quarter of 2025, on a total and per barrel basis, decreased compared to the same period of 2024 reflecting a 60% decline in the realized power price.

Overall, energy operating costs net of power revenue were \$2.06 per barrel in the first quarter of 2025 compared to \$1.19 per barrel in the same period of 2024. Power revenue offset 34% of energy operating costs in the first quarter of 2025 compared to 69% in the comparative 2024 period.

### Capital Expenditures

	Three months ended March 31	
(\$millions)	2025	2024
Sustaining, maintenance and other	\$ 130	\$ 112
Facility expansion project	20	—
Turnaround	7	—
	<b>\$ 157</b>	<b>\$ 112</b>

Capital expenditures increased to \$157 million during the first quarter of 2025 from \$112 million in the same period of 2024, primarily reflecting the planned investment in the facility expansion project ("FEP") and field and facility infrastructure costs.

During 2024, the Corporation reached final investment decision and approved the multi-year Christina Lake FEP which is expected to add 25,000 barrels per day of production capacity, bringing total production capacity to approximately 135,000 barrels per day in 2027, at a total estimated cost of \$470 million. Progress to date is on plan. The Corporation retains the flexibility to reduce capital expenditures in response to changing market conditions, such as declining oil prices, weaker differentials, inflationary cost pressures and potential tariff impacts.

## 5. OUTLOOK

The Corporation's 2025 operating and capital guidance released on November 25, 2024 remains unchanged.

<b>Summary of 2025 Guidance</b>	
Capital expenditures	\$635 million
Bitumen production - annual average	95,000 to 105,000 bbls/d
Non-energy operating costs	\$5.30 to \$5.80 per bbl

The annual production guidance reflects the expected startup of two new well pads in the second half of 2025, supporting increased capacity for future production, as well as an estimated 8,000 barrels per day impact from the planned second quarter turnaround.

The Corporation's \$635 million capital expenditure program includes \$70 million for major planned turnaround activities and \$130 million for the multi-year FEP. The remaining \$435 million in the 2025 capital expenditure program will be allocated to field development and infrastructure to sustain and build future production capacity.

## 6. 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	2025	2024				2023		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
<b>Crude oil prices</b>								
Brent (US\$/bbl)	74.92	73.98	78.47	84.99	81.85	81.61	85.95	78.01
WTI (US\$/bbl)	71.42	70.27	75.09	80.57	76.96	78.32	82.26	73.78
Differential – WTI:WCS – Edmonton (US\$/bbl)	(12.67)	(12.56)	(13.55)	(13.61)	(19.31)	(21.89)	(12.91)	(15.16)
AWB – Edmonton (US\$/bbl)	57.77	56.82	60.62	65.99	55.96	54.53	67.88	56.41
<b>Condensate prices</b>								
Condensate at Edmonton (C\$/bbl)	100.29	98.86	97.10	105.56	98.18	103.90	104.62	97.19
Condensate at Edmonton as a % of WTI	97.9	100.6	94.8	95.7	94.6	97.4	94.8	98.1
Condensate at Mont Belvieu, Texas (US\$/bbl)	64.05	62.86	62.06	64.96	64.52	62.28	64.90	60.54
Condensate at Mont Belvieu, Texas as a % of WTI	89.7	89.5	82.6	80.6	83.8	79.5	78.9	82.1
<b>Natural gas prices</b>								
AECO (C\$/mcf)	2.36	1.61	0.75	1.29	2.72	2.51	2.83	2.67
<b>Electric power prices</b>								
Alberta power pool (C\$/MWh)	40.29	51.73	55.23	45.28	98.87	81.76	151.18	159.87
<b>Foreign exchange rates</b>								
C\$ equivalent of 1 US\$ – average	1.4350	1.3991	1.3636	1.3684	1.3488	1.3618	1.3410	1.3430
C\$ equivalent of 1 US\$ – period end	1.4379	1.4405	1.3505	1.3687	1.3533	1.3205	1.3537	1.3238

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

The average WTI price decreased 7%, to US\$71.42 per barrel, in the first quarter of 2025, relative to the same period of 2024. Subsequent to the first quarter of 2025, WTI prices further declined, primarily driven by an anticipated reduction in oil demand from tariffs on the global economy, exacerbated by OPEC+ announced production increases.

The WCS differential improved US\$6.64 per barrel in the first quarter of 2025, relative to the comparative 2024 period, reflecting unconstrained pipeline egress, low inventories of heavy crude in Western Canada and sustained global demand for heavy crude. As a result, the AWB Edmonton index rose US\$1.81 per barrel, to US\$57.77 per barrel, in the first quarter of 2025, relative to the same period of 2024, reflecting tighter differentials partially offset by a lower WTI price.

### 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 increased as a percentage of WTI in the first quarter of 2025 compared to the same period of 2024. The increase in condensate pricing in the first quarter of 2025 reflects higher diluent demand associated with Western Canada sedimentary basin bitumen production as well as higher petrochemical feedstock demand stemming from modest growth in global manufacturing. The narrower heavy oil differential more than offset the condensate price increase and improved the recovery of diluent costs in blend sales, reducing per barrel diluent expense. The Corporation recovered 83% of diluent costs through blend sales in the three months ended March 31, 2025 compared to 79% in the same period of 2024.

### 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 13%, to \$2.36 per mcf, in the first quarter of 2025, relative to the comparative 2024 period, primarily due to continued strong natural gas production in Alberta.

### 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 59%, to \$40.29 per MWh, in the first quarter of 2025, compared to the same period of 2024, reflecting increasing penetration of renewables, start-up of several new large-scale gas fired generation units and lower natural gas prices.

## 7. OTHER OPERATING RESULTS

### General and Administrative

		Three months ended March 31	
(\$millions, except as indicated)		2025	2024
General and administrative	\$	19	\$ 20
General and administrative expense per barrel of production	\$	2.00	\$ 2.18
Bitumen production - bbls/d		103,224	104,088

## Depletion and Depreciation

	Three months ended March 31	
(\$millions, except as indicated)	2025	2024
Depletion and depreciation expense	\$ 92	\$ 159
Depletion and depreciation expense per barrel of production	\$ 9.86	\$ 16.79
Bitumen production - bbls/d	103,224	104,088

Depletion and depreciation expense decreased by \$67 million during the three months ended March 31, 2025, compared to the same period of 2024. Effective January 1, 2025 field production assets are depleted using the unit-of-production method based on estimated proved developed bitumen reserves. Prior to January 1, 2025, field production assets were depleted using the unit-of-production method based on estimated proved bitumen reserves plus estimated future development costs to develop and produce these proved bitumen reserves. This change in estimate has been applied on a prospective basis resulting in an approximately \$57 million decrease to depletion and depreciation expense during the three months ended March 31, 2025. This change in estimate better allocates costs over the remaining estimated useful lives of the field production assets.

## Stock-based Compensation

	Three months ended March 31	
(\$millions)	2025	2024
Cash-settled expense	\$ 5	\$ 11
Equity-settled expense	14	7
Stock-based compensation expense	\$ 19	\$ 18

During the first quarter of 2025, the Corporation's share price increased 7% compared to 31% in the same period of 2024 and there were fewer cash-settled units outstanding on average in 2025. These factors resulted in a lower cash-settled stock-based compensation expense in the first quarter of 2025.

Equity-settled stock-based compensation expense increased \$7 million in the first quarter of 2025 compared to comparative 2024 period primarily as a result of an increase in the estimated fair value of awards granted.

## Foreign Exchange Gain (Loss)

	Three months ended March 31	
(\$millions)	2025	2024
Unrealized foreign exchange gain (loss) on:		
Long-term debt	\$ 1	\$ (28)
US\$ denominated cash and cash equivalents	(1)	6
Unrealized net gain (loss) on foreign exchange	—	(22)
Realized gain (loss) on foreign exchange	—	(1)
Foreign exchange gain (loss)	\$ —	\$ (23)
C\$ equivalent of 1 US\$		
Beginning of period	1.4405	1.3205
End of period	1.4379	1.3533

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.

There was minimal change in the Canadian dollar exchange rate relative to the U.S. dollar in the first quarter of 2025 resulting in \$nil foreign exchange gain (loss).

During the three months ended March 31, 2024, the Canadian dollar weakened relative to the U.S. dollar by 2% resulting in an unrealized foreign exchange loss of \$22 million.

#### Net Finance Expense

(\$millions)	Three months ended March 31	
	2025	2024
Interest expense on long-term debt	\$ 13	\$ 19
Interest expense on lease liabilities	6	6
Credit facility fees	2	3
Interest income	(1)	(3)
Net interest expense	20	25
Debt extinguishment expense	—	7
Accretion on provisions	3	3
Net finance expense	\$ 23	\$ 35
Average effective interest rate	5.9%	6.2%

Interest expense on long-term debt decreased during the three months ended March 31, 2025, compared to the same period of 2024, primarily reflecting debt repayments in 2024.

During the three months ended March 31, 2024, debt extinguishment expense of \$7 million was recognized on the redemption of US\$105 million of the Corporation's 7.125% senior unsecured notes.

#### Income Tax

(\$millions)	Three months ended March 31	
	2025	2024
Earnings before income taxes	\$ 273	\$ 137
Effective tax rate	23 %	28 %
Income tax expense	\$ 62	\$ 39

At March 31, 2025, the Corporation had approximately \$3.5 billion of available Canadian tax pools, including \$2.1 billion of non-capital losses and \$0.2 billion of capital losses, and recognized a deferred income tax liability of \$422 million.

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



## 8. LIQUIDITY AND CAPITAL RESOURCES

(\$millions)	March 31, 2025	December 31, 2024
<b>Unsecured:</b>		
5.875% senior unsecured notes (Mar 31, 2025 - US\$600 million; due 2029; December 31, 2024 - US\$600 million)	\$ 863	\$ 864
Unamortized deferred debt discount and debt issue costs	(6)	(6)
Current and long-term debt	857	858
Cash and cash equivalents	(88)	(156)
Net debt - C\$ <sup>(1)</sup>	\$ 769	\$ 702
Net debt - US\$ <sup>(1)</sup>	\$ 535	\$ 488

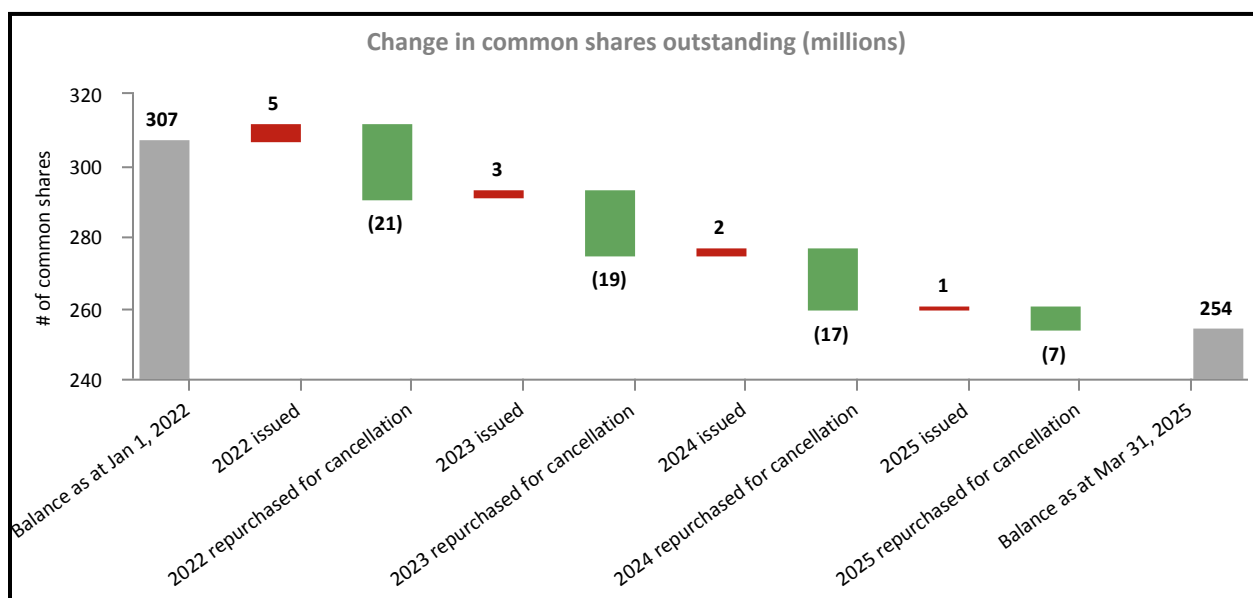
(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 22 of the interim consolidated financial statements.

The Corporation's cash and cash equivalents were \$88 million at March 31, 2025 and \$156 million at December 31, 2024. Refer to the "Cash Flow Summary" section for further details.

The Corporation intends to return 100% of FCF to shareholders through share repurchases and a quarterly base dividend while managing working capital cash requirements.

During the three months ended March 31, 2025, the Corporation repurchased for cancellation 6.7 million shares under its NCIB program at a weighted-average price of \$23.82 per share for a total cost of \$159 million.

On March 6, 2025, the Toronto Stock Exchange approved the renewal of the Corporation's normal course issuer bid ("NCIB"). Pursuant to the NCIB, the Corporation is purchasing its common shares for cancellation, from time to time, as it considers advisable, up to a maximum of 22,535,791 shares. The NCIB became effective on March 11, 2025 and will terminate on March 10, 2026 or such earlier time as the NCIB is completed or terminated at the option of MEG.



The following dividends were declared or paid in 2025:

Board of Directors Declaration Date	Shareholders of Record Date	Payment Date	Amount (C\$/share)
November 5, 2024	December 16, 2024	January 15, 2025	\$0.10
February 27, 2025	March 20, 2025	April 15, 2025	\$0.10
May 6, 2025	June 16, 2025	July 15, 2025	\$0.10

Declaration of dividends is at the discretion of the Board of Directors. 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.

All dividends paid by the Corporation are designated as eligible dividends for Canadian federal income tax purposes.

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

The \$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 facilities, 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.

At March 31, 2025, the Corporation had \$600 million of unutilized capacity under the revolving credit facility and, with \$214 million of issued letters of credit, had \$386 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.

The US\$600 million of 5.875% senior unsecured notes due February 2029 represents the Corporation's only outstanding long-term debt. The outstanding debt is unsecured and contains no financial maintenance covenants.

Commodity market volatility is managed through the Corporation's various financial frameworks. Credit exposure is reduced by targeting sales to primarily investment grade customers. 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

(\$millions)	Three months ended March 31	
	2025	2024
Net cash provided by (used in):		
Operating activities	\$ 296	\$ 317
Investing activities	(175)	(119)
Financing activities	(188)	(279)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	(1)	6
Change in cash and cash equivalents	\$ (68)	\$ (75)

### Cash Flow – Operating Activities

Net cash provided by operating activities during three months ended March 31, 2025 decreased \$21 million, compared to the same period of 2024, primarily due to increased funds used for working capital requirements partially offset by higher cash operating netback.

### Cash Flow – Investing Activities

Net cash used in investing activities increased \$56 million during three months ended March 31, 2025, compared to the same period of 2024, primarily reflecting increased capital spending and funds used for working capital requirements.

### Cash Flow – Financing Activities

Net cash used in financing activities decreased \$91 million during three months ended March 31, 2025, compared to the same period of 2024, primarily reflecting decreased FCF available for share repurchases or dividends.

## 9. SHARES OUTSTANDING

At March 31, 2025, the Corporation had the following share capital instruments outstanding or exercisable:

<i>(thousands)</i>	<b>Units</b>
Common shares:	
Outstanding at December 31, 2024	260,151
Issued upon vesting and release of equity-settled RSUs and PSUs	1,334
Repurchased for cancellation	(6,659)
Common shares outstanding at March 31, 2025	<b>254,826</b>
Convertible securities:	
Equity-settled RSUs and PSUs	<b>2,617</b>

At May 5, 2025, the Corporation had 254.4 million common shares outstanding and 2.6 million equity-settled RSUs and PSUs outstanding.

## 10. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

### Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of obligations at March 31, 2025. 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)	2025	2026	2027	2028	2029	Thereafter	Total
<b>Commitments:</b>							
Transportation and storage <sup>(1)</sup>	\$ 380	\$ 506	\$ 507	\$ 512	\$ 496	\$ 4,691	\$ 7,092
Diluent purchases <sup>(2)</sup>	188	74	65	66	65	32	490
Other operating commitments	15	19	10	9	6	58	117
Variable office lease costs	3	4	4	4	4	8	27
Capital commitments	40	—	—	—	—	—	40
<b>Total Commitments</b>	<b>626</b>	<b>603</b>	<b>586</b>	<b>591</b>	<b>571</b>	<b>4,789</b>	<b>7,766</b>
<b>Other Obligations:</b>							
Lease liabilities <sup>(4)</sup>	28	37	38	38	38	376	555
Long-term debt <sup>(3)</sup>	—	—	—	—	863	—	863
Interest on long-term debt <sup>(3)</sup>	38	51	51	51	6	—	197
Onerous contract <sup>(4)</sup>	8	11	11	11	3	—	44
Decommissioning obligation <sup>(4)</sup>	5	8	8	8	8	858	895
<b>Total Commitments and Obligations</b>	<b>\$ 705</b>	<b>\$ 710</b>	<b>\$ 694</b>	<b>\$ 699</b>	<b>\$ 1,489</b>	<b>\$ 6,023</b>	<b>\$ 10,320</b>

(1) This represents transportation and storage commitments from 2025 to 2048. Excludes amounts recognized on the consolidated balance sheet.

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

(3) This represents the scheduled principal repayments of the senior unsecured notes and associated interest payments based on interest and foreign exchange rates in effect on March 31, 2025.

(4) Represents the undiscounted future obligations associated with these liabilities.

## 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.

## 11. 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.

### Funds from Operations and Free Cash Flow

Funds from operations and free cash flow are capital management measures and are defined in the Corporation's consolidated financial statements. Funds from operations and free cash flow are presented to assist management and investors in analyzing operating performance and cash flow generating ability. Net cash provided by (used in) operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Funds from operations is calculated as net cash provided by (used in) operating activities before the net change in non-cash working capital items. 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 return capital to shareholders. Free cash flow is calculated as funds from operations less capital expenditures.

The following table reconciles Net cash provided by (used in) operating activities to FFO and FCF:

	Three months ended March 31	
(\$millions)	2025	2024
Net cash provided by (used in) operating activities	\$ 296	\$ 317
Net change in non-cash working capital items	\$ 84	\$ 12
Funds from operations	\$ 380	\$ 329
Capital expenditures	(157)	(112)
Free cash flow	\$ 223	\$ 217

### 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, dividends, capital expenditures, or other uses. The per barrel calculation of cash operating netback is based on bitumen sales volumes.

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

	Three months ended March 31	
(\$millions)	2025	2024
Revenues	\$ 1,162	\$ 1,364
Diluent expense	(458)	(456)
Transportation and storage expense	(166)	(130)
Purchased product	(30)	(304)
Operating expenses	(82)	(86)
Realized loss on commodity risk management	—	(4)
Cash operating netback	\$ 426	\$ 384

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

Revenues is an IFRS measure in the Corporation's consolidated statement of earnings and comprehensive income, which is the most directly comparable primary financial statement measure to blend sales and bitumen realization. A reconciliation from revenues to blend sales and bitumen realization has been provided below:

	Three months ended March 31			
	2025		2024	
<i>(\$millions, except as indicated)</i>	\$/bbl		\$/bbl	
Revenues	\$	1,162	\$	1,364
Power and transportation revenue		(11)		(26)
Royalties		108		128
Petroleum revenue		1,259		1,466
Purchased product		(30)		(304)
Blend sales	1,229	\$ 92.48	1,162	\$ 83.58
Diluent expense	(458)	(8.51)	(456)	(10.00)
Bitumen realization	\$	771 \$ 83.97	\$	706 \$ 73.58

### Net Transportation and Storage Expense

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

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

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

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

	Three months ended March 31			
	2025		2024	
<i>(\$millions, except as indicated)</i>	\$/bbl		\$/bbl	
Transportation and storage expense	\$	(166) \$ (18.07)	\$	(130) \$ (13.55)
Power and transportation revenue	\$	11	\$	26
Less power revenue		(10)		(25)
Transportation revenue	\$	1 \$ 0.08	\$	1 \$ 0.07
Net transportation and storage expense	\$	(165) \$ (17.99)	\$	(129) \$ (13.48)

### Bitumen Realization after Net Transportation and Storage Expense

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

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

	Three months ended March 31			
	2025		2024	
<i>(\$millions, except as indicated)</i>	\$/bbl		\$/bbl	
Bitumen realization <sup>(1)</sup>	\$	771	\$	706
Net transportation and storage expense <sup>(1)</sup>		(165)		(129)
Bitumen realization after net transportation and storage expense	\$	606	\$	577

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

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

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

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

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

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

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

	Three months ended March 31			
	2025		2024	
<i>(\$millions, except as indicated)</i>	\$/bbl		\$/bbl	
Non-energy operating costs	\$	(53)	\$	(50)
Energy operating costs		(29)		(36)
Operating expenses	\$	(82)	\$	(86)
Power and transportation revenue	\$	11	\$	26
Less transportation revenue		(1)		(1)
Power revenue	\$	10	\$	25
Operating expenses net of power revenue	\$	(72)	\$	(61)
Energy operating costs net of power revenue	\$	(19)	\$	(11)

## Net Debt

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

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

As at	March 31, 2025	December 31, 2024
Long-term debt	\$ 857	\$ 858
Cash and cash equivalents	(88)	(156)
Net debt - C\$	\$ 769	\$ 702
Net debt - US\$	\$ 535	\$ 488

## 12. 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, 2024.

Effective January 1, 2025, the Corporation made a change to the unit-of-production depletion method to better estimate the allocation of costs over the remaining estimated useful lives of certain assets. Please see note 6 of the interim consolidated financial statements for the period ended March 31, 2025 for further details.

## 13. RISK FACTORS

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

## 14. 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.

## 15. 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.

## 16. ABBREVIATIONS

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

### Financial and Business Environment

<b>AECO</b>	Alberta natural gas price reference location
<b>AIF</b>	Annual Information Form
<b>AWB</b>	Access Western Blend
<b>\$ or C\$</b>	Canadian dollars
<b>EDC</b>	Export Development Canada
<b>eMSAGP</b>	enhanced Modified Steam And Gas Push
<b>ESG</b>	Environment, Social and Governance
<b>FEP</b>	Facility Expansion Project
<b>FSP</b>	Flanagan South and Seaway Pipeline
<b>G&amp;A</b>	General and administrative
<b>GAAP</b>	Generally Accepted Accounting Principles
<b>GHG</b>	Greenhouse Gas
<b>IFRS</b>	International Financial Reporting Standards
<b>NCIB</b>	Normal Course Issuer Bid
<b>MD&amp;A</b>	Management's Discussion and Analysis
<b>OPEC</b>	Organization of Petroleum Exporting Countries
<b>OPEC+</b>	Organization of Petroleum Exporting Countries plus an informal association of other oil producing countries
<b>PSU</b>	Performance Share Units
<b>RSU</b>	Restricted Share Units
<b>SAGD</b>	Steam-Assisted Gravity Drainage
<b>SOR</b>	Steam-oil ratio
<b>SBC</b>	Stock-based compensation
<b>TMX</b>	Trans Mountain Expansion
<b>U.S.</b>	United States
<b>US\$</b>	United States dollars
<b>USGC</b>	United States Gulf Coast
<b>WCS</b>	Western Canadian Select
<b>WTI</b>	West Texas Intermediate

### Measurement

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

## 17. 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 2025 operating and capital guidance, including its expectations regarding 2025 annual average production, capital expenditures and non-energy operating costs; the breakdown of the Corporation's capital expenditures for 2025; the Corporation's expectation of the startup of two new well pads in the second half of 2025, and the impact on production in 2025 from the planned second quarter turnaround; the Corporation's marketing strategy and marketing asset optimization strategy; 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 intent to return 100% of free cash flow to shareholders through share repurchases and a quarterly base dividend, subject to approval of the Corporation's board of directors; the Corporation's belief that the FEP progress is on plan; and 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.

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, price differentials, 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 obtain qualified staff and equipment in a timely and cost-efficient manner; 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; support for protectionism and rising anti-globalization sentiment in the United States and other countries; enacted and proposed export and import restrictions, including but not limited to tariffs, export taxes or curtailment on exports; health, safety and environmental risks, including public health crises, 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; 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](http://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 the leading pure-play in situ thermal oil producer in Canada. Our purpose is to meet the growing demand for energy, produced safely and reliably, while generating long-term value for all our stakeholders. MEG produces, transports and sells our oil (AWB) to customers throughout North America and internationally. Our common shares are listed on the Toronto Stock Exchange under the symbol "MEG" (TSX: 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.

## **18. ADDITIONAL INFORMATION**

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

## 19. QUARTERLY SUMMARIES

	2025	2024				2023		
Unaudited	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
<b>FINANCIAL</b> (\$millions unless specified)								
Net earnings	211	106	167	136	98	103	249	136
Per share, diluted	0.82	0.40	0.62	0.50	0.36	0.37	0.86	0.47
Funds from operations <sup>(1)</sup>	380	340	362	354	329	358	492	278
Per share, diluted	1.47	1.29	1.34	1.30	1.19	1.27	1.71	0.96
Capital expenditures	157	172	141	123	112	104	83	149
Free cash flow <sup>(1)</sup>	223	168	221	231	217	254	409	129
Per share, diluted	0.86	0.64	0.82	0.85	0.78	0.90	1.42	0.45
Working capital	334	300	287	344	226	278	495	231
Net debt - US\$ <sup>(1)</sup>	535	488	478	634	687	730	885	994
Shareholders' equity	4,590	4,553	4,614	4,580	4,511	4,527	4,641	4,441
<b>BUSINESS ENVIRONMENT</b>								
<b>Average Benchmark Commodity Prices:</b>								
WTI (US\$/bbl)	71.42	70.27	75.09	80.57	76.96	78.32	82.26	73.78
Differential – WTI:WCS – Edmonton (US\$/bbl)	(12.67)	(12.56)	(13.55)	(13.61)	(19.31)	(21.89)	(12.91)	(15.16)
AWB – Edmonton (US\$/bbl)	57.77	56.82	60.62	65.99	55.96	54.53	67.88	56.41
Mainline heavy oil pipeline apportionment	5 %	1 %	2 %	5 %	28 %	21 %	1 %	1 %
C\$ equivalent of 1US\$ – average	1.4350	1.3991	1.3636	1.3684	1.3488	1.3618	1.3410	1.3430
Natural gas – AECO (\$/mcf)	2.36	1.61	0.75	1.29	2.72	2.51	2.83	2.67
<b>OPERATIONAL</b> (\$/bbl unless specified)								
Blend sales, net of purchased product – bbls/d	147,715	142,595	145,244	132,812	152,844	158,850	140,002	119,187
Diluent usage – bbls/d	(45,589)	(41,774)	(39,989)	(39,672)	(47,310)	(46,216)	(38,377)	(35,656)
Bitumen sales – bbls/d	102,126	100,821	105,255	93,140	105,534	112,634	101,625	83,531
Bitumen production – bbls/d	103,224	100,139	103,298	100,531	104,088	109,112	103,726	85,974
Steam-oil ratio (SOR)	2.28	2.40	2.36	2.44	2.37	2.28	2.28	2.25
Blend sales <sup>(2)</sup>	92.48	89.00	90.51	98.02	83.58	87.33	101.53	87.81
Diluent expense	(8.51)	(7.42)	(7.25)	(6.91)	(10.00)	(9.58)	(0.06)	(10.27)
Bitumen realization <sup>(2)</sup>	83.97	81.58	83.26	91.11	73.58	77.75	101.47	77.54
Net transportation and storage expense <sup>(2)</sup>	(17.99)	(18.96)	(17.65)	(17.27)	(13.48)	(14.23)	(16.72)	(19.90)
Bitumen realization after net transportation and storage expense <sup>(2)</sup>	65.98	62.62	65.61	73.84	60.10	63.52	84.75	57.64
Royalties	(11.78)	(14.22)	(17.45)	(19.12)	(13.35)	(17.92)	(19.45)	(7.69)
Non-energy operating costs <sup>(3)</sup>	(5.84)	(5.61)	(5.18)	(5.63)	(5.18)	(4.64)	(5.15)	(5.66)
Energy operating costs <sup>(3)</sup>	(3.12)	(2.18)	(1.70)	(2.13)	(3.74)	(3.25)	(3.42)	(3.92)
Power revenue	1.06	1.28	1.06	1.14	2.55	1.79	3.46	2.95
Realized loss on commodity risk management	—	(0.80)	(0.99)	(0.96)	(0.39)	(0.85)	(1.55)	(0.94)
Cash operating netback <sup>(2)</sup>	46.30	41.09	41.35	47.14	39.99	38.65	58.64	42.38
Revenues	1,162	1,147	1,265	1,373	1,364	1,444	1,438	1,291
Power sales price (C\$/MWh)	41.31	52.21	53.64	45.57	102.53	81.66	156.04	150.19
Power sales (MW/h)	112	108	90	100	113	108	97	71
Average cost of diluent (\$/bbl of diluent)	111.56	106.91	109.62	114.25	105.89	110.65	101.68	111.85
Average cost of diluent as a % of WTI	109 %	109 %	107 %	104 %	102 %	104 %	92 %	113 %
Depletion and depreciation rate per bbl of production	9.86	16.37	16.92	16.35	16.79	19.01	15.28	14.88
General and administrative expense per bbl of production	2.00	1.85	1.80	1.98	2.18	1.89	1.73	1.85
<b>COMMON SHARES</b>								
Shares outstanding, end of period (000)	254,826	260,151	266,035	270,142	272,376	274,642	283,290	285,566
Common share price (\$) - close (end of period)	25.23	23.60	25.41	29.27	31.10	23.67	26.43	21.00

(1) Capital management measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.

(2) Non-GAAP financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.

(3) Supplementary financial measure - please refer to section 11 "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 changes in the price of WTI which ranged from a quarterly average of US\$70.27/bbl to US\$82.26/bbl;
- variability in WTI:WCS differential at Edmonton which ranged from a quarterly average of US\$12.56/bbl to US\$21.89/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;
- reaching the US\$600 million net debt target in the third quarter of 2024 allowing the Corporation to return 100% of FCF to shareholders through share repurchases and the introduction of a quarterly base dividend starting in the fourth quarter of 2024;
- changes in depletion and depreciation expense as a result of changes in production rates and future development cost estimates;
- 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;
- changes to the Corporation's depletion methodology in the first quarter of 2025;
- changes in the Corporation's share price and the resulting impact on stock-based compensation; and
- planned turnaround, unplanned outages and other maintenance activities affecting production.

## 20. ANNUAL SUMMARIES

	2024	2023	2022	2021	2020	2019	2018 <sup>(1)</sup>
<b>FINANCIAL</b> ( <i>\$millions unless specified</i> )							
Net earnings (loss)	507	569	902	283	(357)	(62)	(119)
Per share, diluted	1.87	1.98	2.92	0.91	(1.18)	(0.21)	(0.40)
Funds from operations <sup>(2)</sup>	1,385	1,476	1,882	753	239	741	169
Per share, diluted <sup>(2)</sup>	5.13	5.13	6.09	2.42	0.78	2.46	0.56
Adjusted funds flow	1,385	1,402	1,934	826	281	724	175
Per share, diluted	5.13	4.87	6.26	2.65	0.92	2.41	0.58
Capital expenditures	548	449	376	331	149	198	622
Free cash flow <sup>(2)</sup>	837	953	1,558	495	132	526	(447)
Per share, diluted <sup>(2)</sup>	3.10	3.31	5.05	1.59	0.43	1.75	(1.51)
Working capital	300	278	289	150	55	123	290
Net debt - US\$ <sup>(2)</sup>	488	730	1,026	1,897	2,194	2,250	2,508
Shareholders' equity	4,553	4,527	4,383	3,808	3,506	3,853	3,886
<b>BUSINESS ENVIRONMENT</b>							
<b>Average Benchmark Commodity Prices:</b>							
WTI (US\$/bbl)	75.72	77.62	94.23	67.91	39.40	57.03	64.77
Differential – WTI:WCS – Edmonton (US\$/bbl)	(14.76)	(18.71)	(18.27)	(13.04)	(12.60)	(12.76)	(26.31)
AWB – Edmonton (US\$/bbl)	59.84	56.83	73.59	53.20	25.08	42.08	34.78
Mainline heavy oil pipeline apportionment	9 %	9 %	5 %	42 %	24 %	43 %	41 %
C\$ equivalent of 1US\$ – average	1.3700	1.3495	1.3016	1.2536	1.3413	1.3269	1.2962
Natural gas – AECO (\$/mcf)	1.59	2.88	5.79	3.95	2.43	1.92	1.62
<b>OPERATIONAL</b> ( <i>\$/bbl unless specified</i> )							
Blend sales, net of purchased product – bbls/d	143,377	143,063	135,873	131,659	118,347	134,223	125,368
Diluent usage – bbls/d	(42,179)	(41,977)	(40,182)	(39,521)	(35,626)	(40,637)	(38,317)
Bitumen sales – bbls/d	101,198	101,086	95,691	92,138	82,721	93,586	87,051
Bitumen production – bbls/d	102,012	101,425	95,338	93,733	82,441	93,082	87,731
Steam-oil ratio (SOR)	2.39	2.27	2.36	2.43	2.32	2.22	2.19
Blend sales <sup>(3)</sup>	90.02	87.94	102.02	72.20	37.65	61.29	53.47
Diluent expense	(7.90)	(9.30)	(10.07)	(9.73)	(10.42)	(8.08)	(16.78)
Bitumen realization <sup>(3)</sup>	82.12	78.64	91.95	62.47	27.23	53.21	36.69
Net transportation and storage expense <sup>(3)</sup>	(16.81)	(16.18)	(15.29)	(10.93)	(12.92)	(10.84)	(8.42)
Bitumen realization after net transportation & storage expense <sup>(3)</sup>	65.31	62.46	76.66	51.54	14.31	42.37	28.27
Curtailment	—	—	—	—	0.06	(0.37)	—
Royalties	(15.96)	(12.37)	(6.43)	(2.25)	(0.31)	(1.30)	(1.20)
Non-energy operating costs <sup>(4)</sup>	(5.39)	(5.01)	(4.73)	(4.24)	(4.38)	(4.61)	(4.62)
Energy operating costs <sup>(4)</sup>	(2.45)	(4.03)	(7.29)	(4.94)	(3.29)	(2.38)	(1.98)
Power revenue	1.52	3.08	4.11	2.58	1.49	1.75	1.51
Realized gain (loss) on commodity risk management	(0.78)	(0.77)	0.29	(9.32)	11.34	(3.31)	(4.37)
Cash operating netback <sup>(3)</sup>	42.25	43.36	62.61	33.37	19.22	32.15	17.61
Revenues	5,149	5,653	6,118	4,321	2,292	3,931	2,733
Power sales price (C\$/MWh)	64.64	136.50	162.33	90.10	47.81	56.70	47.87
Power sales (MW/h)	103	98	104	115	108	121	114
Average cost of diluent (\$/bbl of diluent)	108.99	110.34	126.00	94.88	61.86	79.89	91.60
Average cost of diluent as a % of WTI	105 %	105 %	103 %	111 %	117 %	106 %	109 %
Depletion and depreciation rate per bbl of production	16.61	16.10	14.57	13.15	13.60	20.90	14.12
General and administrative expense per bbl of production	1.95	1.86	1.78	1.65	1.62	1.99	2.58
<b>COMMON SHARES</b>							
Shares outstanding, end of period (000)	260,151	274,642	291,081	306,865	302,681	299,508	296,841
Common share price (\$) - close (end of period)	23.60	23.67	18.85	11.70	4.45	7.39	7.71

(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 11 "Non-GAAP and Other Financial Measures" of this MD&A.

(3) Non-GAAP financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.

(4) Supplementary financial measure - please refer to section 11 "Non-GAAP and Other Financial Measures" of this MD&A.