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, 2023 was approved by the Corporation's Audit Committee on May 1, 2023. 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, 2023, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2022, the 2022 annual MD&A and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in millions of Canadian dollars, except where otherwise indicated.

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

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

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

   - *Cash operating netback*
   - *Blend sales*
   - *Bitumen realization*
   - *Net transportation and storage 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*
   - *Per barrel figures associated with non-GAAP financial measures*

2. *Supplementary financial measures and ratios:*

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

3. *Capital management measures:*

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

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1. BUSINESS DESCRIPTION

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

MEG owns a 100% working interest in approximately 410 square miles of mineral leases. GLJ Ltd. ("GLJ"), an independent qualified reserves and resources evaluator, estimated that the leases it evaluated, as at December 31, 2022, contained approximately 1.94 billion barrels of gross proved plus probable ("2P") bitumen reserves at the Christina Lake Project. For information regarding MEG's estimated reserves contained in the report prepared by GLJ, please refer to the Corporation's most recently filed AIF, which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

The Christina Lake Project, which contains all the Corporation's 2P reserves has regulatory approval in place for 210,000 bbls/d of production. At a steam-oil ratio of 2.2, MEG has developed oil processing capacity of approximately 110,000 bbls/d at its Christina Lake central plant facility, prior to any impact from scheduled maintenance activity or outages. The typical average annual production decline rate at the Christina Lake Project is approximately 10% to 15% and at an annual production level of approximately 103,700 bbls/d, MEG has a 2P reserve life index of greater than 50 years.

The Corporation has been able to realize production growth over time at the Christina Lake Project while minimizing SOR and associated greenhouse gas ("GHG") emissions intensity through the application of proprietary technologies, including MEG's proprietary reservoir technology, eMSAGP, which reduces the amount of steam required to produce a barrel of bitumen. MEG also uses cogeneration, also known as combined heat and power generation, to create steam and power from a single heat source. The application of eMSAGP and cogeneration have enabled MEG to lower its GHG emissions intensity more than 15% below the *in situ* industry volume weighted average calculated based on data reported to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. In addition, in 2022, as part of a broader development strategy, MEG introduced enhanced completion designs and optimized inter-well spacing all focused on reducing SOR. MEG achieved an average SOR of 2.36 in 2022 compared to the *in situ* industry volume weighted average of 3.0.[1]

Marketing Strategy

The Corporation employs a marketing strategy that delivers and sells its production to oil markets throughout North America and internationally. MEG owns, leases and contracts for services on multiple facilities to transport, store and deliver AWB to customers. MEG has 100,000 bbls/d of contracted AWB transportation capacity on the Flanagan South and Seaway pipeline systems (“FSP”) providing pipeline transportation directly to U.S. Gulf Coast ("USGC") refineries and export terminals. MEG is also a shipper on the Trans Mountain Expansion Project ("TMX") which, when in service, will provide MEG with 20,000 bbls/d of contracted AWB transportation capacity to Canada’s West Coast. MEG has proprietary and contracted oil storage capacity of approximately 2.1 million barrels in Alberta and strategic locations in the U.S., with marine export capacity at Beaumont, Texas in the USGC. This combination of pipeline access, storage capacity and marine export capacity comprises MEG’s strategy of having diversified, long-term and reliable market access to world oil prices for its production.

MEG has a long-term commitment to deliver AWB on the Access Pipeline from its Christina Lake Project to the Edmonton market connecting to local refineries and export pipelines. The Access Pipeline is comprised of an AWB blend pipeline system and diluent pipeline system. The AWB blend pipeline system runs from the Christina Lake Project to Edmonton. The diluent pipeline system runs from the Edmonton area to MEG’s Christina Lake Project and allows MEG to effectively manage its local and import sourced diluent supply for purposes of blending with its Christina Lake production. The diluent system receives volumes from numerous local diluent production streams and fractionation facilities as well as imported diluent volumes from inbound pipelines and rail terminals. The diluent system is well connected to key pipeline and storage systems in the Edmonton/Fort Saskatchewan corridor, including the Enbridge TEPPCO and Southern Lights import pipelines for access to Mont Belvieu supply. This system provides a range of diluent supply alternatives and helps to mitigate diluent supply and price risk.

[1] Annual 2022 data as per the Alberta Energy Regulator ST53.

In the Edmonton area, MEG has approximately 1.1 million barrels of storage and terminalling capacity, including approximately 900,000 barrels of capacity contracted at the Stonefell Terminal. The Stonefell Terminal is connected to the Access Pipeline System and provides the Corporation with the ability to: (i) sell and deliver AWB to a variety of markets; (ii) access multiple sources of diluent; and (iii) store both bitumen blend and diluent in periods of market and transportation disruptions or constraints.

MEG has contracted pipeline capacity, storage capacity and marine export capacity in the USGC area. Specifically, MEG has contracted for approximately 1.0 million barrels of storage capacity, along with marine export capacity, at Beaumont, Texas. MEG has also contracted capacity on the Bayou Bridge pipeline to access USGC refineries and export facilities beyond Texas.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The Corporation generated $161 million of free cash flow during the first quarter of 2023 compared to $471 million in the same period of 2022. Free cash flow and available cash were used to purchase US$86 million (approximately C$117 million) of outstanding 7.125% senior unsecured notes and return $103 million to MEG shareholders through the repurchase and cancellation of 4.9 million shares.

Funds flow from operating activities and adjusted funds flow were $348 million and $274 million in the first quarter of 2023, respectively, compared to $587 million and $559 million in the same quarter of 2022. These decreases reflect a 51% reduction in cash operating netback per barrel mainly due to a lower average WTI price and a wider WTI:AWB differential. Cash operating netback per barrel was also impacted by higher diluent and net transportation and storage expenses, partially offset by lower royalties and operating expenses net of power revenue. The lower cash operating netback, partially offset by reduced income tax expense, drove a decline in net earnings to $81 million in the first quarter of 2023, from $362 million in the first quarter of 2022.

Average bitumen production in the first quarter of 2023 rose to 106,840 barrels per day from 101,128 barrels per day in the same period of 2022, reflecting a continued focus on optimized well spacing, enhanced completion designs, a capital efficient well redevelopment program and targeted facility enhancements. The resulting higher sales volumes partially offset the lower cash operating netback per barrel.

Capital expenditures in the first quarter of 2023 rose $25 million to $113 million, compared with the same period in 2022, reflecting increased drilling activity.

As at March 31, 2023, cash and cash equivalents were $85 million. The Corporation exited the quarter with total debt and net debt of approximately $1.5 billion and $1.4 billion (approximately US$1.0 billion), respectively.

On March 8, 2023, the Toronto Stock Exchange ("TSX") approved the renewal of the Corporation's normal course issuer bid ("NCIB"). Pursuant to the NCIB, the Corporation will purchase for cancellation, from time to time, as it considers advisable, up to a maximum of 28,596,214 of its common shares. The NCIB became effective March 10, 2023 and will terminate on March 9, 2024 or such earlier time as the NCIB is completed or terminated at the option of the Corporation.

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

	2023	2022				2021		
($millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Bitumen production - bbls/d	**106,840**	110,805	101,983	67,256	101,128	100,698	91,506	91,803
Steam-oil ratio	**2.25**	2.22	2.39	2.46	2.43	2.42	2.56	2.39
Bitumen sales - bbls/d	**106,480**	113,582	95,759	73,091	100,186	98,894	92,251	89,980
Bitumen realization after net transportation and storage expense(1) - $/bbl	**43.40**	54.75	74.75	103.29	84.31	59.67	54.88	49.18
Operating expenses - $/bbl	**10.34**	11.05	10.61	16.05	11.54	10.78	9.23	8.11
Operating expenses net of power revenue(1) - $/bbl	**6.13**	5.83	5.45	12.97	8.98	8.20	7.17	5.54
Non-energy operating costs(2) - $/bbl	**4.77**	4.34	4.49	5.65	4.74	4.56	4.46	3.84
Cash operating netback(1) - $/bbl	**34.32**	43.89	62.63	81.75	70.21	37.87	37.31	31.30
General & administrative expense - $/bbl of bitumen production volumes	**1.94**	1.62	1.72	2.37	1.61	1.58	1.72	1.56
Funds flow from operating activities	**348**	383	501	412	587	260	212	160
Per share, diluted	**1.19**	1.28	1.63	1.31	1.87	0.83	0.68	0.51
Adjusted funds flow(3)	**274**	401	496	478	559	274	243	184
Per share, diluted(3)	**0.94**	1.34	1.61	1.52	1.78	0.88	0.78	0.59
Free cash flow(3)	**161**	295	418	374	471	168	159	113
Revenues	**1,480**	1,445	1,571	1,571	1,531	1,307	1,091	1,009
Net earnings (loss)	**81**	159	156	225	362	177	54	68
Per share, diluted	**0.28**	0.53	0.51	0.72	1.15	0.57	0.17	0.22
Capital expenditures	**113**	106	78	104	88	106	84	71
Long-term debt, including current portion	**1,466**	1,581	1,803	2,026	2,440	2,762	2,769	2,820
Net debt(3) - C$	**1,381**	1,389	1,634	1,782	2,150	2,401	2,559	2,661
Net debt(3) - US$	**1,020**	1,026	1,193	1,384	1,722	1,897	2,007	2,145

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

3. SUSTAINABILITY AND PATHWAYS UPDATE

MEG, along with its Pathways Alliance ("Alliance") peers, is progressing pre-work on the proposed foundational carbon capture and storage project, which will transport CO_2 via pipeline from multiple oil sands facilities to be stored safely and permanently in the Cold Lake region of Alberta.

On March 28, 2023 the Canadian federal government announced measures in its 2023 budget to provide greater policy certainty to support and incentivize investment in clean technologies, including carbon capture, utilization and storage ("CCUS") projects, that are critical to meeting Canada's emissions reduction goals. The government indicated a clearer legislative timeline for the previously announced Investment Tax Credit ("ITC") for CCUS. In addition, the federal government committed that contracts for difference would be implemented by the Canada Growth Fund to backstop the future price of, for example, carbon or hydrogen, providing price and revenue predictability that helps to de-risk major projects that reduce Canada's emissions. The Public Sector Pension Investment Board ("PSP Investments") will be mandated to manage the assets of the Canada Growth Fund to allow them to start investing this year. The federal government also committed to consulting on the development of a broad-based approach to carbon contracts for difference that aim to make carbon pricing more predictable and to complement individualized contracts for difference offered by the Canada Growth Fund.

For further details on the Corporation's approach to ESG matters, please refer to the Corporation's 2021 ESG Report and its 2022 ESG Performance Data Supplement available in the "Sustainability" section of the Corporation's website at www.megenergy.com and the most recently filed AIF on www.sedar.com.

4. NET EARNINGS

	Three months ended March 31	
($millions, except per share amounts)	**2023**	**2022**
Net earnings	**$ 81**	$ 362
Per share, diluted	**$ 0.28**	$ 1.15

Net earnings declined to $81 million during the three months ended March 31, 2023 compared to $362 million during the same period of 2022, mainly reflecting a lower cash operating netback partially offset by reduced income tax expense.

5. REVENUES

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

	Three months ended March 31	
($millions)	**2023**	**2022**
Sales from:		
Production	**$ 1,043**	$ 1,393
Purchased product[(1)]	**427**	161
Petroleum revenue	**$ 1,470**	$ 1,554
Royalties	**(31)**	(47)
Petroleum revenue, net of royalties	**$ 1,439**	$ 1,507
Power revenue	**$ 40**	$ 23
Transportation revenue	**1**	1
Other revenue	**$ 41**	$ 24
Revenues	**$ 1,480**	$ 1,531

(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, 2023, petroleum revenue, net of royalties decreased to $1.4 billion from $1.5 billion in the same period of 2022. The decrease primarily reflects lower proprietary sales primarily driven by a weaker average WTI benchmark price and wider WTI:AWB differentials. This was partially offset by increased blend sales volumes, a weaker Canadian dollar relative to the U.S. dollar and lower royalties.

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.

6. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended March 31	
	2023	**2022**
Bitumen production – bbls/d	**106,840**	101,128
Steam-oil ratio (SOR)	**2.25**	2.43

Bitumen Production

Bitumen production increased approximately 6% in the three months ended March 31, 2023, compared to the same period of 2022, reflecting the Corporation's continued focus on optimized well spacing, enhanced completion designs, a capital efficient well redevelopment program and targeted facility enhancements.

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 average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR decreased approximately 8% during the first quarter of 2023, compared to the same period of 2022, due to the deployment of enhanced completion designs, delivery of the 2022 redevelopment plan and focused development of the high-quality resource.

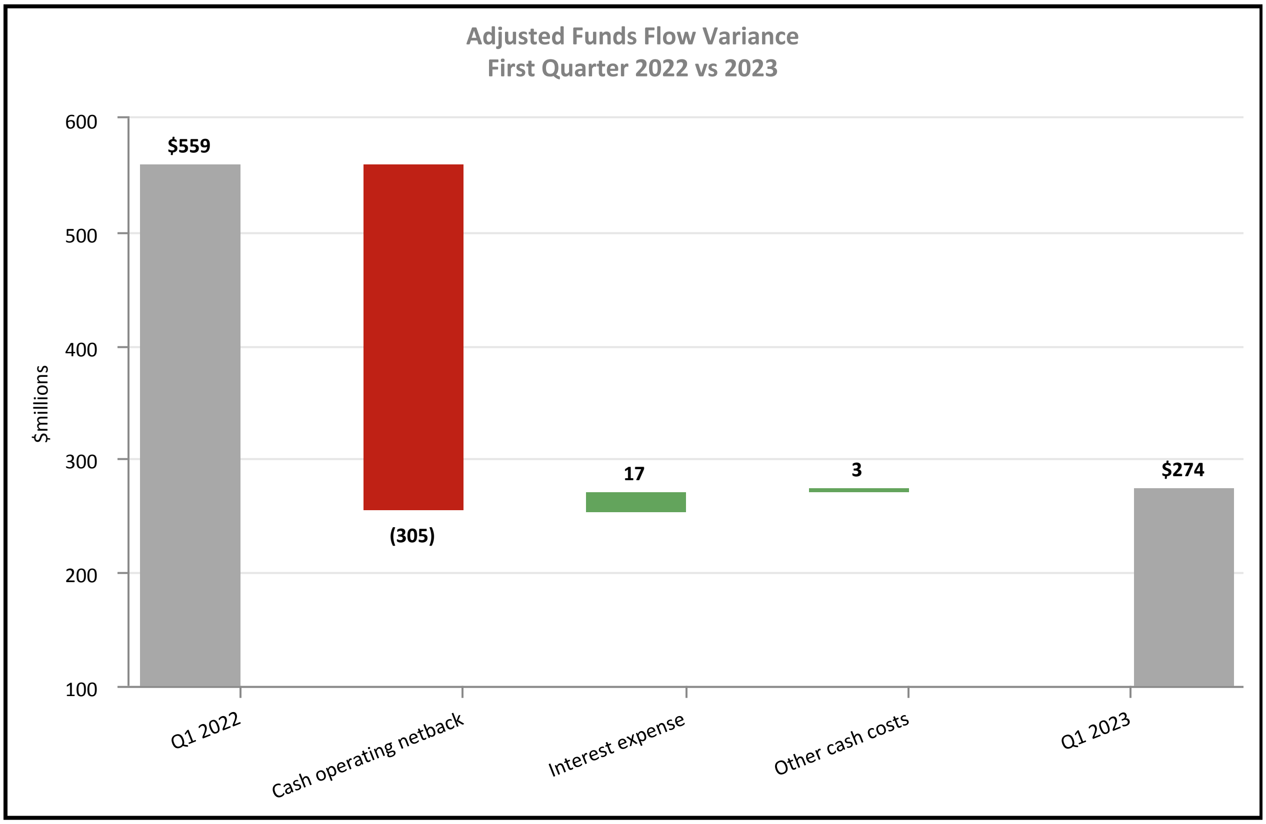
Funds Flow from Operating Activities and Adjusted Funds Flow

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

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

	Three months ended March 31	
($millions)	**2023**	**2022**
Funds flow from operating activities	**$ 348**	$ 587
Adjustments:		
Impact of cash-settled SBC units subject to equity price risk management[(1)]	**13**	18
Realized equity price risk management gain[(1)]	**(87)**	(46)
Adjusted funds flow	**$ 274**	$ 559
Adjusted funds flow per share - diluted	**$ 0.94**	$ 1.78

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



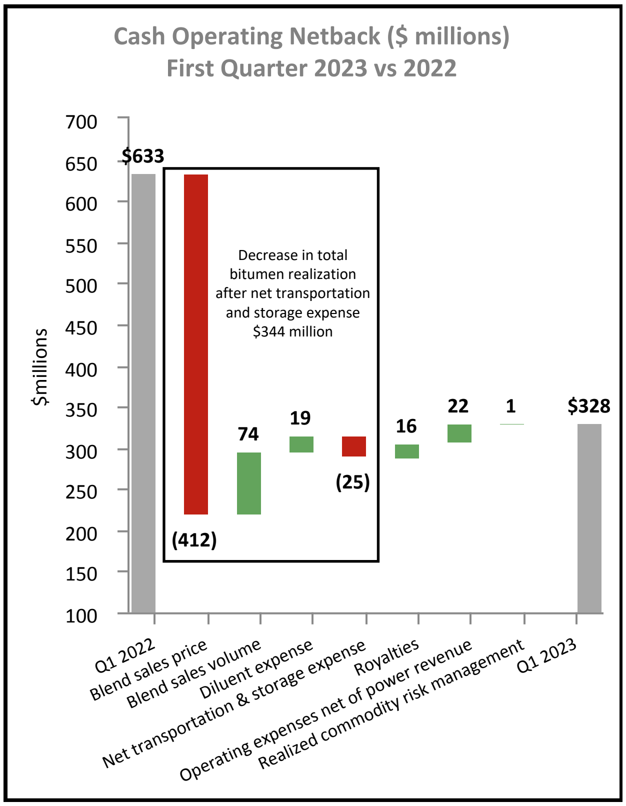
Funds flow from operating activities and adjusted funds flow decreased in the first quarter of 2023, compared to the same period of 2022, driven mainly by a lower cash operating netback. An interest expense decline, reflecting reduced debt levels, partially offset the change in adjusted funds flow.

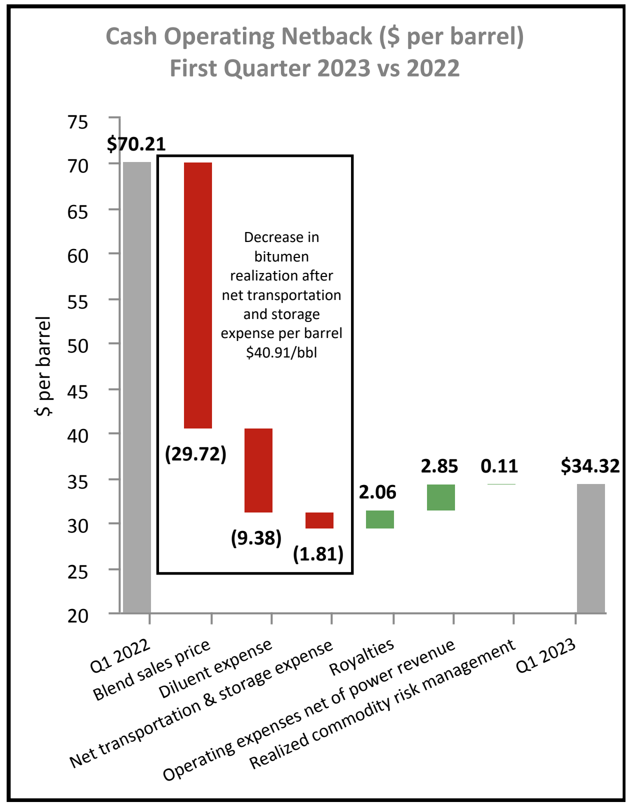
CASH OPERATING NETBACK

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			
	2023		2022	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	**$ 1,043**		$ 1,393	
Sales from purchased product[1]	**427**		161	
Petroleum revenue	**1,470**		1,554	
Purchased product[1]	**(414)**		(160)	
Blend sales[2][3]	**$ 1,056**	**$ 76.07**	$ 1,394	$ 105.79
Diluent expense	**(498)**	**(17.89)**	(517)	(8.51)
Bitumen realization[3]	**558**	**58.18**	877	97.28
Net transportation and storage expense[3][4]	**(142)**	**(14.78)**	(117)	(12.97)
Bitumen realization after net transportation and storage expense[3]	**416**	**43.40**	760	84.31
Royalties	**(31)**	**(3.18)**	(47)	(5.24)
Operating expenses net of power revenue[3]	**(59)**	**(6.13)**	(81)	(8.98)
Realized gain (loss) on commodity risk management	**2**	**0.23**	1	0.12
Cash operating netback[3]	**$ 328**	**$ 34.32**	$ 633	$ 70.21
Bitumen sales volumes - bbls/d		**106,480**		100,186

(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 14 "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, net of third-party recoveries on diluent transportation arrangements.*





During the three months ended March 31, 2023, cash operating netback decreased approximately 50% compared to the same period of 2022. This decrease mainly reflects a lower bitumen realization after net transportation and storage expense partially offset by lower royalties and operating expenses net of power revenue.

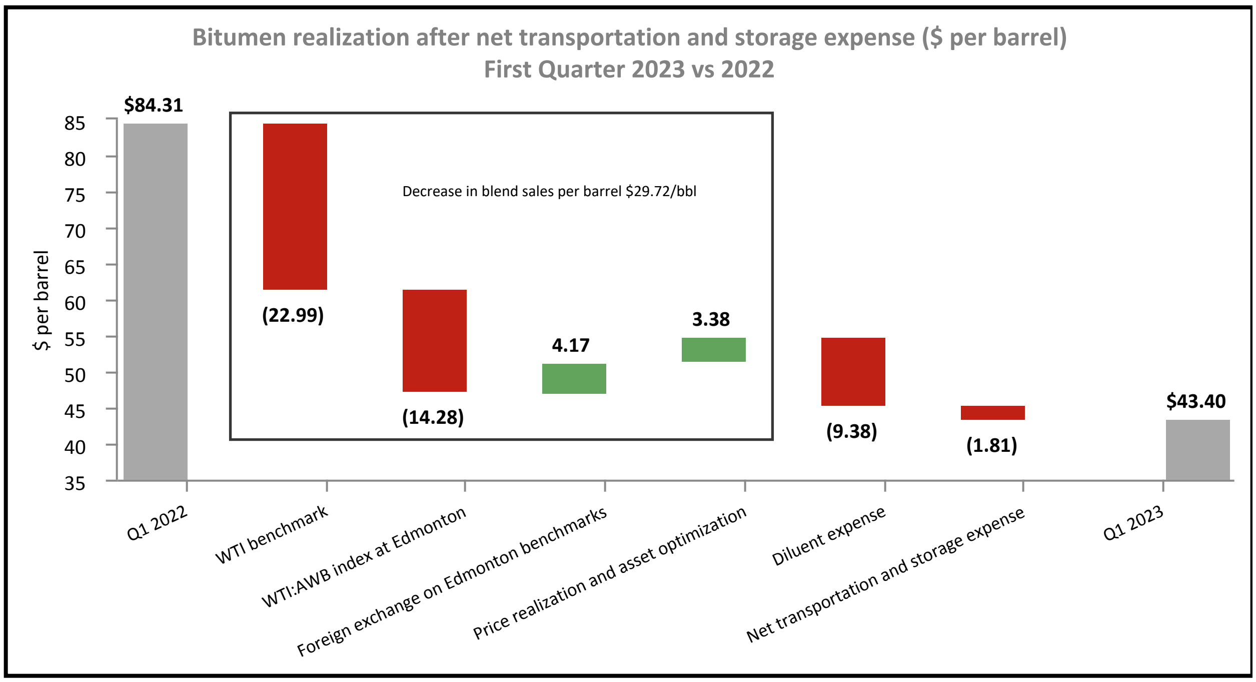
Bitumen Realization after Net Transportation and Storage Expense

Bitumen realization after net transportation and storage expense represents bitumen sales at Christina Lake and is calculated as blend sales less diluent expense and net transportation and storage expense, expressed on a per barrel of bitumen sold basis. Blend sales represents the Corporation's revenue from its oil blend known as AWB, which is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. 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 55% of the diluent is sourced in Edmonton and the rest from Mont Belvieu, Texas. The cost of diluent purchased 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 average benchmark prices and light:heavy oil differentials.

The purchase and sale of third-party products related to marketing asset optimization activities is included in blend sales. 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.

	Three months ended March 31			
	2023		2022	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	$ 1,043		$ 1,393	
Sales from purchased product[(1)]	427		161	
Petroleum revenue	$ 1,470		$ 1,554	
Purchased product[(1)]	(414)		(160)	
Blend sales[(2)(3)]	$ 1,056	$ 76.07	$ 1,394	$ 105.79
Diluent expense	(498)	(17.89)	(517)	(8.51)
Bitumen realization[(3)]	$ 558	$ 58.18	$ 877	$ 97.28
Net transportation and storage expense[(3)]	$ (142)	$ (14.78)	$ (117)	$ (12.97)
Bitumen realization after net transportation and storage expense	$ 416	$ 43.40	$ 760	$ 84.31
Bitumen sales volumes - bbls/d		106,480		100,186

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



Bitumen realization after net transportation and storage expense decreased 49% to $43.40 per barrel in the first quarter of 2023, compared to $84.31 per barrel in the same period of 2022, mainly due to a lower blend sales price, higher diluent expense and increased net transportation and storage expense.

The first quarter of 2023 blend sales price decreased 28%, to $76.07 per barrel, from $105.79 per barrel in the first quarter of 2022. The decrease primarily reflects a lower WTI benchmark price and wider WTI:AWB differentials, at both Edmonton and the USGC, partially offset by a weaker Canadian dollar relative to the U.S. dollar. Also offsetting the decreased benchmark price is $3.38 per barrel related to the realized price impact from diverse market access and marketing activities.

The Corporation sold 56% and 58% of its blend sales volumes in the USGC market during the first quarter of 2023 and 2022, respectively. Average heavy oil apportionment on the Enbridge mainline system was 12% and 10% in those periods.

Diluent expense per barrel in the three months ended March 31, 2023 increased to $17.89 per barrel, compared to $8.51 per barrel in 2022, mainly reflecting a lower recovery of diluent costs through blend sales. Due to wider WTI:AWB differentials applied to the Corporation's blend sales price, the Corporation recovered 66% of the cost of diluent through blend sales compared to a recovery of 85% of the cost of diluent in the same period of 2022.

Total diluent expense decreased to $498 million in the three months ended March 31, 2023 compared to $517 million in the same period of 2022 reflecting a lower average cost of diluent, partially offset by higher diluent volumes used for blending. The cost per barrel of diluent in the first quarter of 2023 was $116.01 compared to $124.23 in the same period of 2022.

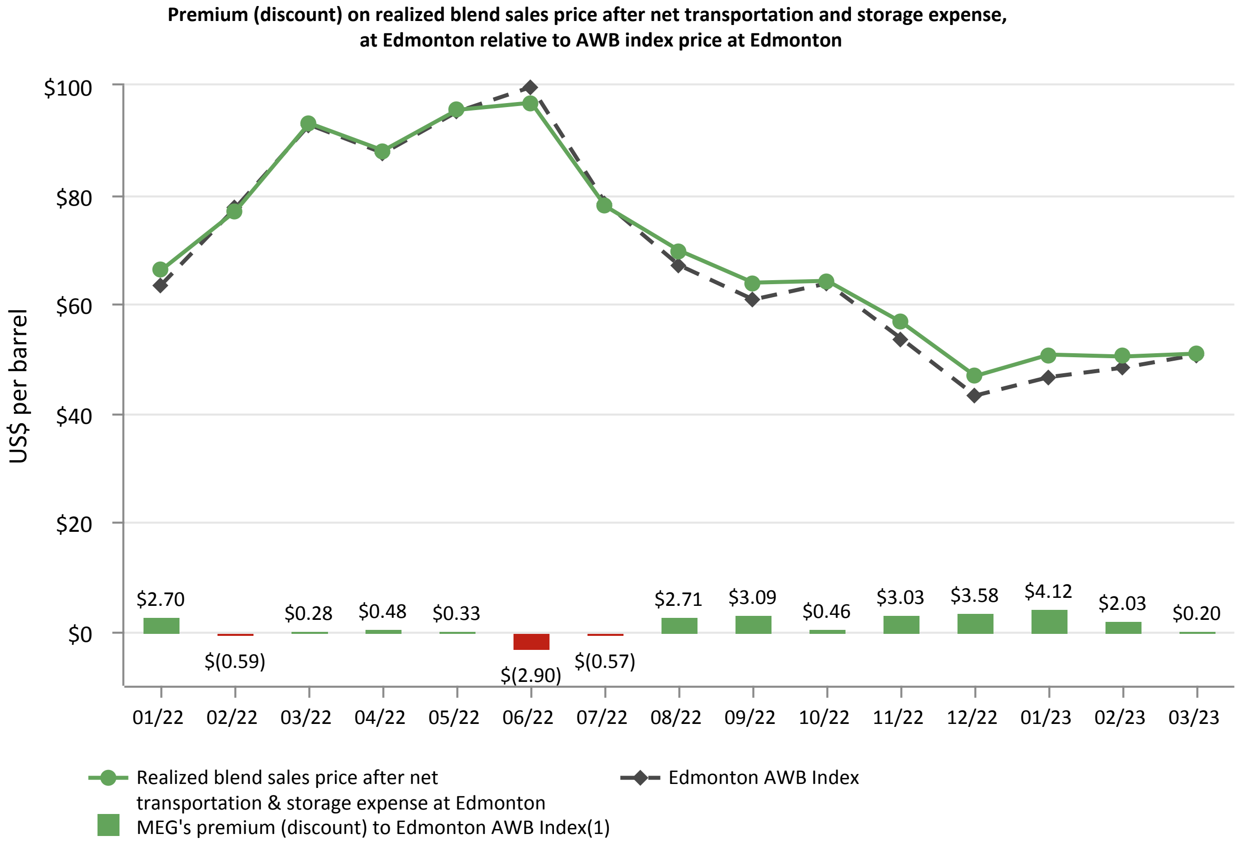
	Three months ended March 31			
	2023		2022	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Transportation and storage expense	**$ (143)**	**$ (14.88)**	$ (118)	$ (13.12)
Transportation revenue	**1**	**0.10**	1	0.15
Net transportation and storage expense	**$ (142)**	**$ (14.78)**	$ (117)	$ (12.97)
Bitumen sales volumes - bbls/d		**106,480**		100,186

Net transportation and storage expense in the three months ended March 31, 2023, on a total and a per barrel basis, rose relative to the same period of 2022. The increase mainly reflects higher base tolls on FSP and a weaker Canadian dollar relative to the U.S. dollar. Higher bitumen sales volumes also increased the total net transportation and storage expense.

When expressed on a US$ per barrel of blend sales basis, net transportation and storage expense was US$7.55 during the first quarter of 2023 compared to US$7.01 during the same period of 2022.

The Corporation partially mitigated the cost of transportation and storage assets through the purchase and sale of non-proprietary product. These asset optimization activities added $13 million, or $0.93 per barrel, to blend sales in the first quarter of 2023 compared to $1 million, or $0.04 per barrel, in the same period of 2022.

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



(1) *Quarterly premium (discount) on realized blend sales price after net transportation and storage expense, at Edmonton relative to AWB index price at Edmonton is calculated on volume-weighted average basis.*

In the first quarters of 2023 and 2022, the Corporation's ability to access the USGC increased the realized blend sales price compared to the Edmonton AWB index by US$2.25 and US$0.93 per barrel, respectively.

Royalties

The Oil Sands Royalty Regulation, 2009, establishes royalty rates that are linked to WTI 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 every dollar the WTI oil price in Canadian dollars is priced above $55 per barrel, to a maximum of 9% when the Canadian 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 WTI price is $120 per barrel or higher.

The Corporation’s Christina Lake operation remained in pre-payout status during the first quarter of 2023 and will reach payout in the second quarter.

($millions)	Three months ended March 31 2023		2022	
Bitumen realization	**$**	**558**	$	877
Transportation and storage expense		**(143)**		(118)
Transportation revenue		**1**		1
Bitumen realization after net transportation and storage expense	**$**	**416**	$	760
Royalties	**$**	**31**	$	47
Effective royalty rate[(1)(2)]		**7.5 %**		6.2 %

(1) Effective royalty rate is calculated as royalties divided by bitumen realization after net transportation and storage expense.
(2) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

Lower royalties during the three months ended March 31, 2023 reflect a lower realized price which reduced gross revenue compared to the same period of 2022.

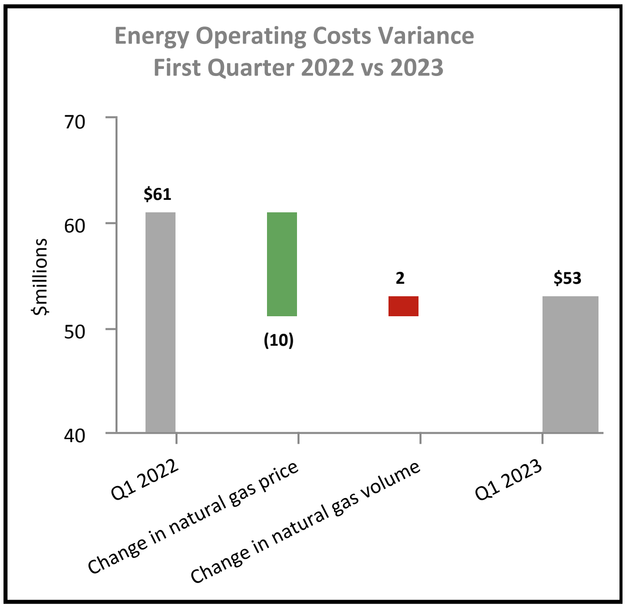
Operating Expenses net of Power Revenue

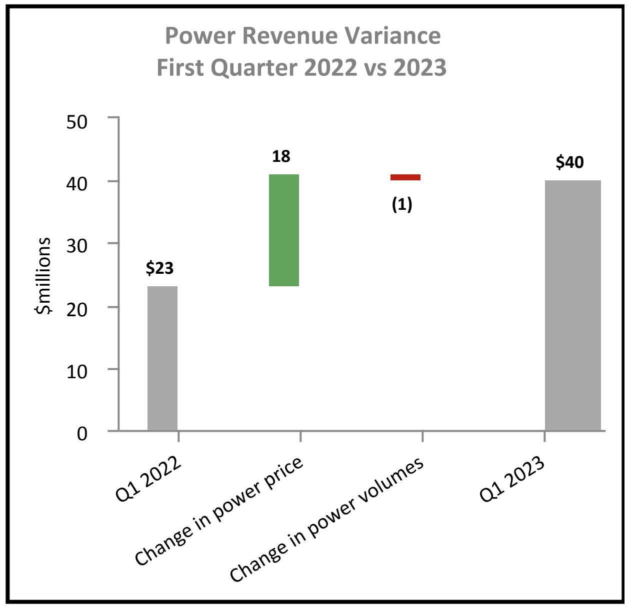
Operating expenses net of power revenue are comprised of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-oriented operating activities and energy operating costs reflect the cost of natural gas used for fuel to generate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

($millions, except as indicated)	Three months ended March 31 2023				2022			
				$/bbl				**$/bbl**
Non-energy operating costs[(1)]	**$**	**(46)**	**$**	**(4.77)**	$	(43)	$	(4.74)
Energy operating costs[(1)]		**(53)**		**(5.57)**		(61)		(6.80)
Operating expenses		**(99)**		**(10.34)**		(104)		(11.54)
Power revenue		**40**		**4.21**		23		2.56
Operating expenses net of power revenue[(2)]	**$**	**(59)**	**$**	**(6.13)**	$	(81)	$	(8.98)
Energy operating costs net of power revenue[(2)]	**$**	**(13)**	**$**	**(1.36)**	$	(38)	$	(4.24)
Average delivered natural gas price (C$/mcf)			**$**	**4.54**			$	5.35
Average realized power sales price (C$/Mwh)			**$**	**162.90**			$	91.50

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

Non-energy operating costs in the first quarter of 2023, on a total and per barrel basis, were consistent with the same period of 2022.





Lower energy operating costs in the first quarter of 2023, on a total and per barrel basis, reflect a weaker AECO natural gas price relative to the same period of 2022. On a total dollar basis, this decrease was partially offset by an increase in purchased natural gas volumes in the first quarter of 2023.

Power revenue increased during the first quarter of 2023, compared to the same period of 2022, as the realized power price increased by 78%.

Energy operating costs net of power revenue decreased to $1.36 per barrel during the first quarter of 2023, compared to $4.24 per barrel during the same period of 2022, mainly reflecting a 78% increase in realized power prices and a weaker AECO natural gas price.

Realized Gain (Loss) on Commodity Risk Management

The Corporation periodically enters financial commodity risk management contracts to partially manage exposure on blend sales, condensate purchases, natural gas purchases and power sales. Financial commodity risk management contracts are also used to eliminate price risk on marketing asset optimization activities pursuant to Board approved policies.

Refer to the commodity risk management discussion within the "OTHER OPERATING RESULTS" section of this MD&A for further details.

	Three months ended March 31			
	2023		**2022**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Realized gain (loss) on commodity risk management	**$ 2**	**$ 0.23**	$ 1	$ 0.12

Capital Expenditures

	Three months ended March 31	
($millions)	**2023**	**2022**
Sustaining and maintenance	**$ 112**	$ 80
Field infrastructure, corporate and other	**1**	8
	$ 113	$ 88

Capital expenditures in the first quarter of 2023 increased $25 million, compared to the same period of 2022, reflecting increased drilling activity.

7. OUTLOOK

The 2023 capital and operating guidance released on November 28, 2022 remains unchanged.

The Corporation has capacity to ship 100,000 bbls/d of AWB blend sales, on a pre-apportionment basis, to the USGC market via its committed FSP capacity. In addition, 20,000 bbls/d of capacity is contracted on the TMX pipeline system to Canada's west coast. TMX is scheduled to come into service in early 2024, which will further broaden MEG's market access.

Summary of 2023 Guidance	
Capital expenditures	$450 million
Bitumen production - annual average	100,000 - 105,000 bbls/d
Non-energy operating costs	$4.75 - $5.05 per bbl
G&A expense	$1.70 - $1.90 per bbl

(1) 2023 guidance includes the impact of the scheduled second quarter turnaround which is expected to impact annual production by approximately 6,000 barrels per day.

8. BUSINESS ENVIRONMENT

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

AVERAGE BENCHMARK COMMODITY PRICES	2023	2022				2021		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Crude oil prices								
Brent (US$/bbl)	**82.21**	88.59	97.69	111.57	97.23	79.78	73.15	68.98
WTI (US$/bbl)	**76.13**	82.65	91.55	108.41	94.29	77.19	70.56	66.07
Differential – WTI:WCS – Edmonton (US$/bbl)	**(24.88)**	(25.89)	(19.86)	(12.80)	(14.53)	(14.64)	(13.58)	(11.49)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(27.63)**	(29.14)	(22.80)	(14.25)	(16.35)	(16.40)	(15.13)	(13.11)
AWB – Edmonton (US$/bbl)	**48.50**	53.51	68.75	94.16	77.94	60.79	55.43	52.96
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(14.87)**	(16.35)	(10.15)	(6.15)	(5.85)	(6.40)	(5.57)	(3.92)
AWB – U.S. Gulf Coast (US$/bbl)	**61.26**	66.30	81.40	102.26	88.44	70.79	64.99	62.15
Enbridge Mainline heavy crude apportionment %	**12**	5	3	0	10	21	53	46
Condensate prices								
Condensate at Edmonton (C$/bbl)	**107.91**	113.17	113.97	138.39	121.74	99.70	87.30	81.55
Condensate at Edmonton as % of WTI	**104.8**	100.9	95.3	100.0	102.0	102.5	98.2	100.5
Condensate at Mont Belvieu, Texas (US$/bbl)	**68.13**	64.57	72.25	90.98	92.68	76.62	68.19	61.18
Condensate at Mont Belvieu, Texas as a % of WTI	**89.5**	78.1	78.9	83.9	98.3	99.3	96.6	92.6
Natural gas prices								
AECO (C$/mcf)	**3.51**	5.57	4.54	7.89	5.16	5.07	3.92	3.37
Electric power prices								
Alberta power pool (C$/MWh)	**141.63**	213.66	221.90	122.49	90.47	107.25	100.27	104.73
Foreign exchange rates								
C$ equivalent of 1 US$ – average	**1.3520**	1.3577	1.3059	1.2766	1.2661	1.2600	1.2602	1.2280
C$ equivalent of 1 US$ – period end	**1.3528**	1.3534	1.3700	1.2872	1.2484	1.2656	1.2750	1.2405

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.

Relative to the first quarter of 2022, crude oil prices weakened in the first quarter of 2023 as a result of increased supply certainty and the potential for reduced global demand. During the first half 2022, global crude pricing strengthened as the Russian invasion of Ukraine and subsequent sanctions against Russia created concern for significant oil supply disruption. The relatively muted impact of sanctions on Russian production and the price cap on Russian crude oil and products combined to ease supply uncertainty and exert downward pressure on crude pricing in the latter half of 2022. Pricing weakened further in the first quarter of 2023 due to growing global recessionary concerns and the perceived negative impact on oil demand.

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

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

WTI:AWB differentials at both Edmonton and the USGC widened in the first quarter of 2023 mainly as a result of the same supply/demand factors that impacted global crude oil prices.

Enbridge Mainline Heavy Crude Apportionment

Enbridge Mainline heavy crude apportionment was 12% and 10% during the first quarters of 2023 and 2022, respectively. The significant decrease since early 2021 reflects the Enbridge Line 3 Replacement project which restored 370,000 barrels per day of Western Canadian crude egress. Reduced apportionment allows the Corporation to utilize its committed FSP capacity enabling a higher percentage of sales in the USGC market.

Condensate Prices

In order to facilitate pipeline transportation, the Corporation uses condensate as diluent for blending with the Corporation’s 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, as a percentage of WTI, during the three months ended March 31, 2023 strengthened 3%, compared to the same period of 2022, primarily due to local condensate supply tightness. Condensate pricing during the three months ended March 31, 2023 at Mont Belvieu, Texas weakened 9% compared to the same period of 2022 due to a reduction in international demand.

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. AECO natural gas decreased approximately 32% in the first quarter of 2023 relative to the same period of 2022 primarily due to an unseasonably mild winter dampening demand, record natural gas production in North America and significantly reduced export pricing for natural gas.

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 strengthened by 57% in the first quarter of 2023 compared to the same period of 2022. The increase reflects the pass through of facility operating cost escalation including higher carbon tax costs, increased offer pricing for marginal power generation in Alberta, and elevated export market pricing.

9. OTHER OPERATING RESULTS

General and Administrative

		Three months ended March 31		
($millions, except as indicated)		**2023**		**2022**
General and administrative	**$**	**18**	$	14
General and administrative expense per barrel of production	**$**	**1.94**	$	1.61
Bitumen production - bbls/d		**106,840**		101,128

General and administrative ("G&A") expense during the three months ended March 31, 2023 increased compared to the same period of 2022 primarily due to higher staff costs.

Depletion and Depreciation

		Three months ended March 31		
($millions, except as indicated)		**2023**		**2022**
Depletion and depreciation expense	**$**	**143**	$	124
Depletion and depreciation expense per barrel of production	**$**	**14.86**	$	13.58
Bitumen production - bbls/d		**106,840**		101,128

During the three months ended March 31, 2023, depletion and depreciation expense rose by $19 million, compared to the same period of 2022, due to an increase in the per barrel depletion and depreciation rate from higher estimated future development costs, and increased production.

Commodity Risk Management Gain (Loss), Net

The Corporation periodically enters 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. 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.

	Three months ended March 31	
($millions)	**2023**	**2022**
Realized gain (loss) on:		
Condensate contracts[1]	**$ 4**	$ —
Natural gas contracts[2]	**(3)**	1
Marketing asset optimization contracts[3]	**1**	—
Realized commodity risk management gain (loss)	**$ 2**	$ 1
Unrealized gain (loss) on:		
Condensate contracts[1]	**$ 12**	$ —
Natural gas contracts[2]	**(12)**	4
Unrealized commodity risk management gain (loss)	**$ —**	$ 4
Commodity risk management gain (loss)	**$ 2**	$ 5

(1) Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas relative to WTI.
(2) Relates to contracts which fix the AECO price on natural gas purchases.
(3) The Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months to support marketing asset optimization activities.

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

	Three months ended March 31	
(US$/bbl, unless otherwise indicated)	**2023**	**2022**
Condensate purchase contracts:		
Average fixed differential[1]	**$ (11.44)**	$ (11.30)
Average settlement differential	**(8.00)**	(1.61)
Gain (loss) on condensate purchase contracts	**$ 3.44**	$ 9.69
Natural gas purchase contracts:		
Average fixed price (C$/GJ)	**$ 3.88**	$ 2.50
Average settlement price (C$/GJ)	**3.06**	4.49
Gain (loss) on natural gas purchase contracts (C$/GJ)	**$ (0.82)**	$ 1.99

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

Stock-based Compensation

	Three months ended March 31	
($millions)	**2023**	**2022**
Cash-settled expense	**$ 18**	$ 44
Equity-settled expense	**8**	4
Equity price risk management gain[1]	**(9)**	(42)
Stock-based compensation expense (recovery)	**$ 17**	$ 6

(1) Relates to financial derivatives entered to manage the Corporation's exposure to cash-settled restricted share units ("RSUs") and performance share units ("PSUs") vesting in 2021, 2022 and 2023 granted under the Corporation's stock-based compensation plans. Amounts are unrealized until vesting of the related units occurs. See section 13 "Risk Management" of this MD&A for further details.

The cash-settled expense during the first quarter of 2023 was lower than the same period of 2022 as the Corporation's share price increased more significantly in the first quarter of 2022 compared to the first quarter of 2023. Also, there were less units vesting during the first quarter of 2023 compared to the same period of 2022. All of the Corporation's outstanding cash-settled RSUs and PSUs vested during the first quarter of 2023. Director share units ("DSUs") are the only cash-settled units remaining outstanding as at March 31, 2023.

The equity price risk management gain is driven by the change in the Corporation's common share price relative to the notional value of the instruments. The $9 million and $42 million equity price risk management gains in the first quarters of 2023 and 2022, respectively, reflect the increased share price in each of those periods. As at March 31, 2023, all outstanding cash-settled RSUs and PSUs were fully vested and the related financial equity price risk management contract was fully realized.

Foreign Exchange Gain (Loss), Net

	Three months ended March 31	
($millions)	**2023**	**2022**
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ —**	$ 31
Foreign currency risk management contracts	**—**	7
US$ denominated cash and cash equivalents	**(1)**	(9)
Unrealized net gain (loss) on foreign exchange	**(1)**	29
Realized gain (loss) on foreign exchange	**—**	(1)
Foreign exchange gain (loss), net	**$ (1)**	$ 28

C$ equivalent of 1 US$		
Beginning of period	**1.3534**	1.2656
End of period	**1.3528**	1.2484

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

The Canadian dollar exchange rate, relative to the U.S. dollar, was consistent at March 31, 2023 and December 31, 2022.

During the three months ended March 31, 2022, the Canadian dollar strengthened 1% relative to the U.S. dollar resulting in an unrealized foreign exchange gain of $29 million.

Net Finance Expense

	Three months ended March 31	
($millions)	**2023**	**2022**
Interest expense on long-term debt	**$ 29**	$ 47
Interest expense on lease liabilities	**6**	6
Interest income	**(2)**	—
Net interest expense	**33**	53
Debt extinguishment expense	**4**	—
Accretion on provisions	**3**	2
Net finance expense	**$ 40**	$ 55

Average effective interest rate	**6.5%**	6.7%

Interest expense on long-term debt decreased during the three months ended March 31, 2023, compared to the same period of 2022, primarily reflecting the US$877 million (approximately $1.2 billion) in debt reduction since April 1, 2022.

For the three months ended March 31, 2023, debt extinguishment expense of $4 million was recognized in association with the repurchase and extinguishment of US$86 million (approximately C$117 million) of the Corporation's 7.125% senior unsecured notes, which included a cumulative debt redemption premium of $3 million and associated unamortized deferred debt issue costs of $1 million. Refer to Note 8 of the interim consolidated financial statements for further details.

Income Tax

	Three months ended March 31	
($millions)	**2023**	**2022**
Earnings before income taxes	**$ 110**	$ 466
Effective tax rate	**26 %**	22 %
Income tax expense	**$ 29**	$ 104

As at March 31, 2023, the Corporation had approximately $5.5 billion of available Canadian tax pools, including $3.9 billion of non-capital losses and $0.4 billion of capital losses, and recognized a deferred income tax liability of $52 million.

The effective tax rate for the three months ended March 31, 2023 differed from the Canadian statutory rate of 23% primarily due to the tax effect of non-taxable stock-based compensation expense for equity-settled plans.

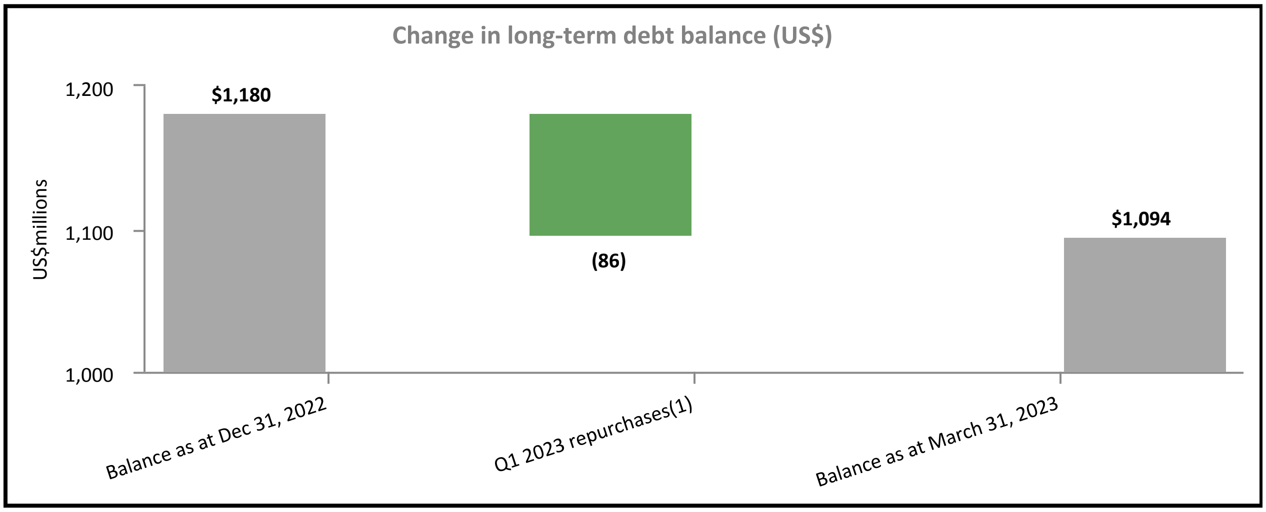
10. LIQUIDITY AND CAPITAL RESOURCES

($millions)	**March 31, 2023**	**December 31, 2022**
Unsecured:		
7.125% senior unsecured notes (March 31, 2023 - US$493.9 million; due 2027; December 31, 2022 - US$579.9 million)	**$ 668**	$ 785
5.875% senior unsecured notes (March 31, 2023 - US$600 million; due 2029; December 31, 2022 - US$600 million)	**812**	812
Unamortized deferred debt discount and debt issue costs	**(14)**	(16)
Current and long-term debt	**1,466**	1,581
Cash and cash equivalents	**(85)**	(192)
Net debt - C$[1]	**$ 1,381**	$ 1,389
Net debt - US$[1]	**$ 1,020**	$ 1,026

(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 19 of the interim consolidated financial statements.

(2) On April 14, 2023, S&P Global Ratings raised the Corporation's long-term issuer credit rating to BB- and a stable outlook from B+ and affirmed the issue-level rating on the Corporation's senior unsecured notes at BB-.

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



(1) *Weighted average repurchase price of 102.2% plus accrued and unpaid interest on US$86 million of the Corporation's 7.125% senior unsecured notes due 2027.*

The Corporation's cash and cash equivalents balance was $85 million at March 31, 2023 compared to $192 million at December 31, 2022. Refer to the "Cash Flow Summary" section for further details.

The Corporation's net debt was US$1.0 billion at March 31, 2023 and December 31, 2022.

At the beginning of 2022, the Corporation started allocating all free cash flow to debt reduction. During the second quarter of 2022, upon reaching net debt of US$1.7 billion, the Corporation initiated the allocation of approximately 25% of free cash flow to share buybacks with the remainder applied to debt reduction. At the end of the third quarter of 2022, net debt declined to US$1.2 billion and free cash flow allocated to share buybacks was raised to approximately 50% with the remainder applied to debt reduction. The current free cash flow allocation strategy will remain in place until net debt reaches US$600 million, which is expected to occur beyond 2023 at current oil prices.

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$493.9 million of 7.125% senior unsecured notes due February 2027 represents the earliest long-term debt maturity. Additionally, the modified covenant-lite $600 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $300 million or 50%. If drawn in excess of $300 million, or 50%, the Corporation is required to maintain a quarterly first lien net leverage ratio (first lien net debt to last twelve-month EBITDA) of 3.5 or less. Under the Corporation's credit facility, first lien net debt is calculated as debt under the revolving credit facility plus other debt that is secured on a *pari passu* basis with the revolving credit facility, less cash-on-hand. None of the outstanding long-term debt contains financial maintenance covenants or is secured on a *pari passu* basis with the revolving credit facility.

At March 31, 2023, the Corporation's $600 million revolving credit facility was undrawn and $155 million of unutilized capacity remained 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 project development are dependent on factors discussed in the "RISK FACTORS" section of this MD&A.

Cash Flow Summary

	Three months ended March 31	
($millions)	**2023**	**2022**
Net cash provided by (used in):		
Operating activities	**$ 237**	$ 317
Investing activities	**(111)**	(88)
Financing activities	**(232)**	(291)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(1)**	(9)
Change in cash and cash equivalents	**$ (107)**	$ (71)

Cash Flow – Operating Activities

Net cash provided by operating activities during the three months ended March 31, 2023 decreased, compared to the same period of 2022, primarily due to lower realized crude oil prices.

Cash Flow – Investing Activities

Net cash used in investing activities increased $23 million during the three months ended March 31, 2023, compared to the same period of 2022, reflecting increased capital spending.

Cash Flow – Financing Activities

Net cash used in financing activities decreased $59 million during the three months ended March 31, 2023, compared to the same period of 2022, primarily due to decreased debt repayment partially offset by share buybacks under the Corporation's capital allocation strategy.

11. RISK MANAGEMENT

Commodity Price Risk Management

The Corporation periodically enters financial commodity risk management contracts to manage exposure on blend sales, condensate purchases, natural gas purchases and power sales. Financial commodity risk management contracts are also used to eliminate price risk on marketing asset optimization activities pursuant to Board approved policies.

The Corporation 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 (Loss) and comprehensive income (loss) and in cash operating netback as the contracts are realized.

The Corporation had the following financial commodity risk management contracts relating to condensate purchases and natural gas purchases outstanding at March 31, 2023:

As at March 31, 2023			
Condensate Purchase Contracts	**Volumes (bbls/d)**	**Term**	**Average Price (US$/bbl)**
WTI:Mont Belvieu Fixed Differential	10,000	Apr 1, 2023 - Oct 31, 2023	$(11.44)
Natural Gas Purchase Contracts	**Volumes (GJ/d)**	**Term**	**Average Price (C$/GJ)**
AECO Fixed Price	35,000	Apr 1, 2023 - Dec 31, 2023	$3.88
AECO Fixed Price	30,000	Jan 1, 2024 - Dec 31, 2024	$4.11

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

The following table summarizes the sensitivity of cash operating netback, adjusted funds flow and earnings (loss) before income tax of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place at March 31, 2023:

Commodity	Sensitivity Range	Increase	Decrease
Condensate purchase price	± 5% in condensate price as a percentage of WTI	$ 11	$ (11)
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	$ 10	$ (10)

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 (loss), the unrealized asset (liability) is included in risk management on the balance sheet and any realized asset outstanding at period-end is included in trade receivables and other on the balance sheet. In March 2020, the Corporation entered financial equity price risk management contracts to manage exposure on cash-settled RSUs and PSUs vesting between April 1, 2021 and March 31, 2023.

	Three months ended March 31	
($millions)	**2023**	**2022**
Unrealized equity price risk management (gain) loss	**$ 78**	$ 4
Realized equity price risk management (gain) loss	**(87)**	(46)
Equity price risk management (gain) loss	**$ (9)**	$ (42)

(1) As at March 31, 2023, all outstanding cash-settled RSUs and PSUs were fully vested and the related financial equity price risk management contract was fully realized. DSUs are the only cash-settled units remaining outstanding as at March 31, 2023.

12. SHARES OUTSTANDING

At March 31, 2023, the Corporation had the following share capital instruments outstanding or exercisable:

(thousands)	**Units**
Common shares:	
Outstanding at December 31, 2022	291,081
Issued upon exercise of stock options	96
Issued upon vesting and release of RSUs and PSUs	2,377
Repurchased for cancellation	(4,940)
Common shares outstanding at March 31, 2023	**288,614**
Convertible securities:	
Stock options[1]	**198**
Equity-settled RSUs and PSUs	**3,876**

(1) *All outstanding stock options were exercisable at March 31, 2023.*

In the first quarter of 2023, the Corporation repurchased for cancellation 4.9 million common shares under its NCIB program at a weighted average price of $20.88 for a total cost of $103 million.

At April 28, 2023, the Corporation had 287.7 million common shares outstanding, 0.2 million stock options outstanding and exercisable and 3.9 million equity-settled RSUs and equity-settled PSUs outstanding.

13. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of obligations at March 31, 2023. 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)	**2023**	**2024**	**2025**	**2026**	**2027**	**Thereafter**	**Total**
Commitments:							
Transportation and storage[1]	$ 324	$ 468	$ 441	$ 419	$ 422	$ 5,028	$ 7,102
Diluent purchases	126	12	—	—	—	—	138
Other operating commitments	13	17	17	17	8	24	96
Variable office lease costs	3	4	4	4	5	17	37
Capital commitments	29	—	—	—	—	—	29
Total Commitments	495	501	462	440	435	5,069	7,402
Other Obligations:							
Lease obligations	28	38	30	28	29	434	587
Current and long-term debt[2]	—	—	—	—	668	812	1,480
Interest on long-term debt[2]	71	95	95	95	54	54	464
Decommissioning obligation[3]	3	4	3	3	3	817	833
Total Commitments and Obligations	**$ 597**	**$ 638**	**$ 590**	**$ 566**	**$ 1,189**	**$ 7,186**	**$ 10,766**

(1) *This represents transportation and storage commitments from 2023 to 2048, including pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet.*

(2) *This represents the scheduled principal repayments of the senior unsecured notes and associated interest payments based on interest and foreign exchange rates in effect on March 31, 2023.*

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

Contingencies

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

14. NON-GAAP AND OTHER FINANCIAL MEASURES

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

Adjusted Funds Flow and Free Cash Flow

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

In the second quarter of 2022, an adjustment was made to the presentation of adjusted funds flow and free cash flow. In April 2020, the Corporation issued cash-settled RSUs under its long-term incentive ("LTI") plan when the share price was at a historic low of $1.57 per share. Concurrent with the issuance, the Corporation entered equity price risk management contracts to manage share price volatility in the subsequent three-year period, effectively reducing share price appreciation cash flow risk. The increase in the Corporation's share price from April 2020 to June 30, 2022 resulted in the recognition of a significant cash-settled stock-based compensation expense, which was previously included as a component of adjusted funds flow and free cash flow. The actual cash impact of the 2020 cash-settled RSUs, however, is subject to equity price risk management contracts, so the cash impact over the term of these RSUs has been reduced and the change in value does not provide a valuable indication of operating performance.

Therefore, the financial statement impacts of the April 2020 cash-settled stock-based compensation and the equity price risk management contracts have been excluded from adjusted funds flow and free cash flow. All prior periods presented have been adjusted to reflect this change in presentation. The adjustments to prior periods are as follows:

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

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

	Three months ended March 31	
($millions)	**2023**	**2022**
Funds flow from operating activities	**$ 348**	$ 587
Adjustments:		
Impact of cash-settled SBC units subject to equity price risk management	**13**	18
Realized equity price risk management gain	**(87)**	(46)
Adjusted funds flow	**274**	559
Capital expenditures	**(113)**	(88)
Free cash flow	**$ 161**	$ 471

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, 2023**	**December 31, 2022**
Long-term debt	**$ 1,466**	$ 1,578
Current portion of long-term debt	**—**	3
Cash and cash equivalents	**(85)**	(192)
Net debt - C$	**$ 1,381**	$ 1,389
Net debt - US$	**$ 1,020**	$ 1,026

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 (loss) and comprehensive income (loss) which is the most directly comparable primary financial statement measure to cash operating netback. A reconciliation from revenues to cash operating netback has been provided below:

	Three months ended March 31	
($millions)	**2023**	**2022**
Revenues	**$ 1,480**	$ 1,531
Diluent expense	**(498)**	(517)
Transportation and storage expense	**(143)**	(118)
Purchased product	**(414)**	(160)
Operating expenses	**(99)**	(104)
Realized gain (loss) on commodity risk management	**2**	1
Cash operating netback	**$ 328**	$ 633

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 (loss) and comprehensive income (loss), which is the most directly comparable primary financial statement measure to blend sales and bitumen realization. A reconciliation from revenues to blend sales and bitumen realization has been provided below:

	Three months ended March 31			
	2023		**2022**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Revenues	**$ 1,480**		$ 1,531	
Other revenue	**(41)**		(24)	
Royalties	**31**		47	
Petroleum revenue	**1,470**		1,554	
Purchased product	**(414)**		(160)	
Blend sales	**1,056**	**$ 76.07**	1,394	$105.79
Diluent expense	**(498)**	**(17.89)**	(517)	(8.51)
Bitumen realization	**$ 558**	**$ 58.18**	$ 877	$ 97.28

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 (loss) and comprehensive income (loss).

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

	Three months ended March 31			
	2023		2022	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Transportation and storage expense	**$ (143)**	**$ (14.88)**	$ (118)	$ (13.12)
Other revenue	**$ 41**		$ 24	
Less power revenue	**(40)**		(23)	
Transportation revenue	**$ 1**	**$ 0.10**	$ 1	$ 0.15
Net transportation and storage expense	**$ (142)**	**$ (14.78)**	$ (117)	$ (12.97)

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			
	2023		2022	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Bitumen realization(1)	**$ 558**	**$ 58.18**	$ 877	$ 97.28
Net transportation and storage expense(1)	**(142)**	**(14.78)**	(117)	(12.97)
Bitumen realization after net transportation and storage expense	**$ 416**	**$ 43.40**	$ 760	$ 84.31

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

	Three months ended March 31			
	2023		**2022**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Non-energy operating costs	**$ (46)**	**$ (4.77)**	$ (43)	$ (4.74)
Energy operating costs	**(53)**	**(5.57)**	(61)	(6.80)
Operating expenses	**$ (99)**	**$ (10.34)**	$ (104)	$ (11.54)
Other revenue	**$ 41**		$ 24	
Less transportation revenue	**(1)**		(1)	
Power revenue	**$ 40**	**$ 4.21**	$ 23	$ 2.56
Operating expenses net of power revenue	**$ (59)**	**$ (6.13)**	$ (81)	$ (8.98)
Energy operating costs net of power revenue	**$ (13)**	**$ (1.36)**	$ (38)	$ (4.24)

Effective royalty rate

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

Effective royalty rate enables a comparison between pre- and post-payout Crown royalties by calculating a royalty rate on a consistent basis. The actual royalty rate applied will differ from the effective royalty rate.

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

	Three months ended March 31	
($millions)	**2023**	**2022**
Bitumen realization	**$ 558**	$ 877
Transportation and storage expense	**(143)**	(118)
Transportation revenue	**1**	1
Bitumen realization after net transportation and storage expense	**$ 416**	$ 760
Royalties	**$ 31**	$ 47
Effective royalty rate	**7.5 %**	6.2 %

15. 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 significant accounting policies and the significant accounting estimates, assumptions and judgments can be found in the Corporation's annual consolidated financial statements for the year ended December 31, 2022.

16. RISK FACTORS

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

17. DISCLOSURE CONTROLS AND PROCEDURES

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

18. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

19. ABBREVIATIONS

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

Financial and Business Environment

AECO	Alberta natural gas price reference location
AIF	Annual Information Form
AWB	Access Western Blend
$ or C$	Canadian dollars
DSU	Deferred share units
EDC	Export Development Canada
eMSAGP	enhanced Modified Steam And Gas Push
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
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
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam-oil ratio
SBC	Stock-based compensation
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

20. ADVISORY

Forward-Looking Information

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

Forward-looking statements are often, but not always, identified by such words. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. In particular, and without limiting the foregoing, this document contains forward looking statements with respect to: the Corporation's business strategy, focus and future plans; statements regarding the Corporation's estimated reserves; MEG's intentions with respect to its normal course issuer bid and the effects of repurchases of common shares thereunder; the Corporation's ESG mid-term and long-term targets and actions the Corporation is undertaking to achieve these targets; the Corporation's expectations regarding the Pathways Alliance projects and government support of these projects; the Corporation's expectation that the Christina Lake Project has an oil processing capacity of approximately 110,000 bbls/d at a current steam oil-oil ratio of 2.2 prior to any impact from scheduled maintenance activity or outages; the impact on SOR of the Corporation's enhanced completion designs and its development and redevelopment plans; the Corporation's marketing strategy and marketing asset optimization strategy; the Corporation's expectation that the Christina Lake operation will reach payout for royalty purposes in the second quarter of 2023; the Corporation's ability to sell excess power into the Alberta electrical grid to displace other power sources that have a higher carbon intensity, thereby reducing the Corporation's overall carbon footprint; all statements relating to the Corporation's annual 2023 guidance, including its full year production, non-energy operating costs, G&A expense, capital expenditures and transportation costs and all statements relating to the Corporation's effective royalty rate; the Corporation's expectation that TMX will come into service in early 2024; the Corporation's expectations regarding global crude oil prices and global crude oil demand and supply balances; the Corporation's expectation of allocating 50% of free cash flow to share buybacks with the remaining cash flow applied to ongoing debt reduction until it reaches a net debt floor of US$600 million, which is expected to occur beyond 2023 at current oil prices; the Corporation's continued focus on debt reduction as a key component of its capital allocation strategy; the Corporation's expectations regarding its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business; and the Corporation's statements regarding its 2023 hedge book.

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

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

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

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

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

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

Estimates of Reserves and Resources

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

21. ADDITIONAL INFORMATION

Additional information relating to the Corporation, including its AIF, is available on the Corporation's website at www.megenergy.com and is also available on SEDAR at www.sedar.com.

22. QUARTERLY SUMMARIES

	2023	2022				2021		
Unaudited	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**81**	159	156	225	362	177	54	68
Per share, diluted	**0.28**	0.53	0.51	0.72	1.15	0.57	0.17	0.22
Funds flow from operating activities	**348**	383	501	412	587	260	212	160
Per share, diluted	**1.19**	1.28	1.63	1.31	1.87	0.83	0.68	0.51
Adjusted funds flow(1)	**274**	401	496	478	559	274	243	184
Per share, diluted(1)	**0.94**	1.34	1.61	1.52	1.78	0.88	0.78	0.59
Capital expenditures	**113**	106	78	104	88	106	84	71
Free cash flow(1)	**161**	295	418	374	471	168	159	113
Working capital	**219**	289	395	437	465	150	199	127
Net debt - C$(1)	**1,381**	1,389	1,634	1,782	2,150	2,401	2,559	2,661
Net debt - US$(1)	**1,020**	1,026	1,193	1,384	1,722	1,897	2,007	2,145
Shareholders' equity	**4,370**	4,383	4,418	4,339	4,178	3,808	3,628	3,564
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**76.13**	82.65	91.55	108.41	94.29	77.19	70.56	66.07
Differential – WTI:WCS – Edmonton (US$/bbl)	**(24.88)**	(25.89)	(19.86)	(12.80)	(14.53)	(14.64)	(13.58)	(11.49)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(27.63)**	(29.14)	(22.80)	(14.25)	(16.35)	(16.40)	(15.13)	(13.11)
AWB – Edmonton (US$/bbl)	**48.50**	53.51	68.75	94.16	77.94	60.79	55.43	52.96
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(14.87)**	(16.35)	(10.15)	(6.15)	(5.85)	(6.40)	(5.57)	(3.92)
AWB – U.S. Gulf Coast (US$/bbl)	**61.26**	66.30	81.40	102.26	88.44	70.79	64.99	62.15
Enbridge Mainline heavy apportionment	**12 %**	5 %	3 %	0 %	10 %	21 %	53 %	46 %
C$ equivalent of 1US$ – average	**1.3520**	1.3577	1.3059	1.2766	1.2661	1.2600	1.2602	1.2280
Natural gas – AECO ($/mcf)	**3.51**	5.57	4.54	7.89	5.16	5.07	3.92	3.37
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**154,197**	160,163	131,327	105,517	146,382	141,280	127,546	129,474
Diluent usage – bbls/d	**(47,717)**	(46,581)	(35,568)	(32,426)	(46,196)	(42,386)	(35,295)	(39,494)
Bitumen sales – bbls/d	**106,480**	113,582	95,759	73,091	100,186	98,894	92,251	89,980
Bitumen production – bbls/d	**106,840**	110,805	101,983	67,256	101,128	100,698	91,506	91,803
Steam-oil ratio (SOR)	**2.25**	2.22	2.39	2.46	2.43	2.42	2.56	2.39
Blend sales(2)	**76.07**	83.28	99.96	128.20	105.79	82.43	74.54	69.27
Diluent expense	**(17.89)**	(14.12)	(9.63)	(5.51)	(8.51)	(11.37)	(9.63)	(9.18)
Net transportation and storage expense(2)	**(14.78)**	(14.41)	(15.58)	(19.40)	(12.97)	(11.39)	(10.03)	(10.91)
Bitumen realization after net transportation and storage expense(2)	**43.40**	54.75	74.75	103.29	84.31	59.67	54.88	49.18
Royalties	**(3.18)**	(5.15)	(7.47)	(8.67)	(5.24)	(3.54)	(2.67)	(1.71)
Non-energy operating costs(3)	**(4.77)**	(4.34)	(4.49)	(5.65)	(4.74)	(4.56)	(4.46)	(3.84)
Energy operating costs(3)	**(5.57)**	(6.71)	(6.12)	(10.40)	(6.80)	(6.22)	(4.77)	(4.27)
Power revenue	**4.21**	5.22	5.16	3.08	2.56	2.58	2.06	2.57
Realized gain (loss) on commodity risk management	**0.23**	0.12	0.80	0.10	0.12	(10.06)	(7.73)	(10.63)
Cash operating netback(2)	**34.32**	43.89	62.63	81.75	70.21	37.87	37.31	31.30
Revenues	**1,480**	1,445	1,571	1,571	1,531	1,307	1,091	1,009
Power sales price (C$/MWh)	**162.90**	219.81	217.25	117.94	91.50	95.22	82.17	88.40
Power sales (MW/h)	**118**	116	98	82	121	117	101	113
Average cost of diluent ($/bbl of diluent)	**116.01**	117.72	125.91	140.61	124.23	108.96	99.69	90.18
Average cost of diluent as a % of WTI	**113 %**	105 %	105 %	102 %	104 %	112 %	112 %	111 %
Depletion and depreciation rate per bbl of production	**14.86**	15.84	14.30	14.35	13.58	13.63	12.78	12.99
General and administrative expense per bbl of production	**1.94**	1.62	1.72	2.37	1.61	1.58	1.72	1.56
COMMON SHARES								
Shares outstanding, end of period (000)	**288,614**	291,081	301,649	307,271	307,596	306,865	306,773	306,716
Common share price ($) - close (end of period)	**21.71**	18.85	15.46	17.82	17.07	11.70	9.89	8.97

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

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

- significant variability in blend sales pricing primarily due to high volatility in the price of WTI which ranged from a quarterly average of US$66.07/bbl to US$108.41/bbl;
- variability in WTI:AWB differentials;
- the cost of diluent due to changes in Canadian and U.S. benchmark pricing, the timing of diluent inventory purchases and the impact of foreign exchange;
- changes in the value of the Canadian dollar relative to the U.S. dollar and its impact on blend sales prices, the cost of diluent, interest expense, and foreign exchange gains and losses associated with the Corporation's U.S. dollar denominated debt;
- timing of capital projects;
- inflationary pressure;
- apportionment and the ability to reach USGC markets;
- fluctuations in natural gas and power pricing;
- gains and losses on risk management contracts;
- changes in depletion and depreciation expense as a result of changes in production rates and future development costs;
- changes in the Corporation's share price and the resulting impact on stock-based compensation and financial equity price risk management contracts; and
- planned turnaround and other maintenance activities affecting production.

23. ANNUAL SUMMARIES

	2022	2021	2020	2019	2018[1]	2017[1]	2016[1]
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	902	283	(357)	(62)	(119)	166	(429)
Per share, diluted	2.92	0.91	(1.18)	(0.21)	(0.40)	0.57	(1.90)
Funds flow from operating activities	1,882	753	239	741	169	343	(69)
Per share, diluted	6.09	2.42	0.78	2.46	0.56	1.18	(0.31)
Adjusted funds flow[2]	1,934	826	281	724	175	371	(63)
Per share, diluted[2]	6.26	2.65	0.92	2.41	0.58	1.28	(0.28)
Capital expenditures	376	331	149	198	622	508	140
Free cash flow[2]	1,558	495	132	526	(447)	(137)	(203)
Working capital	289	150	55	123	290	313	96
Net debt - C$[2]	1,389	2,401	2,798	2,917	3,422	4,205	4,897
Net debt - US$[2]	1,026	1,897	2,194	2,250	2,508	3,359	3,647
Shareholders' equity	4,383	3,808	3,506	3,853	3,886	3,964	3,287
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/bbl)	94.23	67.91	39.40	57.03	64.77	50.95	43.33
Differential – WTI:WCS – Edmonton (US$/bbl)	(18.27)	(13.04)	(12.60)	(12.76)	(26.31)	(11.98)	(13.84)
Differential – WTI:AWB – Edmonton (US$/bbl)	(20.64)	(14.71)	(14.32)	(14.95)	(29.99)	(14.09)	(16.40)
AWB – Edmonton (US$/bbl)	73.59	53.20	25.08	42.08	34.78	36.86	26.93
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	(9.62)	(4.60)	(4.77)	(1.77)	(6.68)	(7.61)	(11.53)
AWB - U.S. Gulf Coast (US$/bbl)	84.61	63.31	34.63	55.26	58.09	43.34	31.80
Enbridge Mainline heavy apportionment	5 %	42 %	24 %	43 %	41 %	20 %	12 %
C$ equivalent of 1US$ – average	1.3016	1.2536	1.3413	1.3269	1.2962	1.2980	1.3256
Natural gas – AECO ($/mcf)	5.79	3.95	2.43	1.92	1.62	2.29	2.25
OPERATIONAL **($/bbl unless specified)**							
Blend sales, net of purchased product – bbls/d	135,873	131,659	118,347	134,223	125,368	115,766	116,586
Diluent usage – bbls/d	(40,182)	(39,521)	(35,626)	(40,637)	(38,317)	(35,766)	(36,159)
Bitumen sales – bbls/d	95,691	92,138	82,721	93,586	87,051	80,000	80,427
Bitumen production – bbls/d	95,338	93,733	82,441	93,082	87,731	80,774	81,245
Steam-oil ratio (SOR)	2.36	2.43	2.32	2.22	2.19	2.31	2.29
Blend sales[3]	102.02	72.20	37.65	61.29	53.47	51.39	38.19
Diluent expense	(10.07)	(9.73)	(10.42)	(8.08)	(16.78)	(9.36)	(10.28)
Net transportation and storage expense[3]	(15.29)	(10.93)	(12.92)	(10.84)	(8.42)	(6.89)	(6.46)
Bitumen realization after net transportation & storage expense[3]	76.66	51.54	14.31	42.37	28.27	35.14	21.45
Curtailment	—	—	0.06	(0.37)	—	—	—
Royalties	(6.43)	(2.25)	(0.31)	(1.30)	(1.20)	(0.77)	(0.29)
Non-energy operating costs[4]	(4.73)	(4.24)	(4.38)	(4.61)	(4.62)	(4.62)	(5.62)
Energy operating costs[4]	(7.29)	(4.94)	(3.29)	(2.38)	(1.98)	(2.98)	(3.01)
Power revenue	4.11	2.58	1.49	1.75	1.51	0.76	0.64
Realized gain (loss) on commodity risk management	0.29	(9.32)	11.34	(3.31)	(4.37)	(0.39)	0.08
Cash operating netback[3]	62.61	33.37	19.22	32.15	17.61	27.14	13.25
Revenues	6,118	4,321	2,292	3,931	2,733	2,474	1,866
Power sales price (C$/MWh)	162.33	90.10	47.81	56.70	47.87	21.49	18.74
Power sales (MW/h)	104	115	108	121	114	118	115
Average cost of diluent ($/bbl of diluent)	126.00	94.88	61.86	79.89	91.60	72.32	61.06
Average cost of diluent as a % of WTI	103 %	111 %	117 %	106 %	109 %	109 %	106 %
Depletion and depreciation rate per bbl of production	14.57	13.15	13.60	20.90	14.12	16.13	16.81
General and administrative expense per bbl of production	1.78	1.65	1.62	1.99	2.58	2.94	3.24
COMMON SHARES							
Shares outstanding, end of period (000)	291,081	306,865	302,681	299,508	296,841	294,104	226,467
Common share price ($) - close (end of period)	18.85	11.70	4.45	7.39	7.71	5.14	9.23

(1) *The Corporation adopted IFRS 16 Leases, effective January 1, 2019, therefore prior periods have not been restated.*
(2) *Capital management measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.*
(3) *Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.*
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