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, 2022 was approved by the Corporation's Audit Committee on May 2, 2022. 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, 2022, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2021, the 2021 annual MD&A and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in millions of Canadian dollars, except where otherwise indicated.

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

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

1. *Non-GAAP financial measures and ratios:*
    - *Cash operating netback*
    - *Blend sales*
    - *Bitumen realization*
    - *Transportation and storage expense net of transportation revenue*
    - *Operating expenses net of power revenue*
    - *Per barrel figures associated with non-GAAP financial measures*
2. *Supplementary financial measures and ratios:*
    - *Non-energy operating costs*
    - *Energy operating costs*
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3. *Capital management measures:*
    - *Adjusted funds flow*
    - *Free cash flow*
    - *Net debt*

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1. BUSINESS DESCRIPTION

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

MEG owns a 100% working interest in approximately 410 square miles of mineral leases. GLJ Ltd. ("GLJ"), an independent qualified reserves and resources evaluator, estimated that the leases it had evaluated, as at December 31, 2021, contained approximately 2.0 billion barrels of gross proved plus probable ("2P") bitumen reserves 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.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

Global crude oil prices strengthened in the first quarter of 2022 as a result of improved demand and declining inventories. With the February 2022 Russian invasion of Ukraine, the imposition of sanctions against Russia caused significant upward pressure on global crude oil prices driven by concerns over potential for major disruptions to global crude oil supply. As a result of this increased pricing and strong production performance, the Corporation generated both funds flow from operating activities and adjusted funds flow of $587 million in the first quarter of 2022 compared to $121 million and $127 million, respectively, in the first quarter of 2021. The Corporation's realized blend sales price averaged $105.79 per barrel in the first quarter of 2022 compared to $61.28 per barrel in the first quarter of 2021 resulting primarily from a US$36.45 per barrel increase in the WTI benchmark price.

Production volumes averaged a record 101,128 barrels per day in the first quarter of 2022 compared to 90,842 barrels per day during the first quarter of 2021 and 100,698 barrels per day in the fourth quarter of 2021. Increased steam utilization and ongoing optimization and recompletion work all contributed to strong field-wide production performance to date in 2022. Also contributing to the increase was the Corporation's commitment in the last half of 2021 to increase spending on incremental well capital aimed at fully utilizing the 100,000 barrels per day processing capacity of the Christina Lake plant.

Capital expenditures were $88 million in the first quarter of 2022 compared to $70 million during the first quarter of 2021. The majority of the $88 million invested in the quarter was directed towards sustaining and maintenance activities. The Corporation continues to maintain annual 2022 capital expenditures guidance of $375 million.

Free cash flow in the first quarter of 2022 hit a quarterly record of $499 million. This compares to $57 million in the first quarter of 2021.

The Corporation recognized net earnings of $362 million in the first quarter of 2022 compared to a net loss of $17 million in the first quarter of 2021. Increased earnings were mainly due to stronger global crude oil prices. The net loss recognized in the first quarter of 2021 was impacted by losses on commodity risk management. The Corporation has not entered into any WTI or WTI:WCS differential commodity risk management contracts for 2022.

On January 18, 2022 debt totaling US$225 million was redeemed and the announced redemption of the remaining balance of the Corporation's 6.50% senior secured second lien notes of US$171 million occurred subsequent to the first quarter on April 4, 2022. Post these redemptions, the Corporation will have repaid approximately US$2 billion of outstanding indebtedness since 2018 and remains committed to continued debt reduction as a key component of its capital allocation strategy in 2022.

As at March 31, 2022 cash and cash equivalents were $290 million. The Corporation exited the quarter with net debt of approximately $2.15 billion (approximately US$1.72 billion) compared to net debt of approximately $2.40 billion (approximately US$1.90 billion) at December 31, 2021.

On March 7, 2022, the Corporation received approval from the Toronto Stock Exchange ("TSX") for a normal course issuer bid ("NCIB") which will allow the Corporation to purchase for cancellation, from time to time, as the

Corporation considers advisable, up to a maximum of 27,242,211 common shares of the Corporation. The NCIB became effective March 10, 2022 and will terminate on March 9, 2023 or such earlier time as the NCIB is completed or terminated at the option of the Corporation. The Corporation's net debt balance at the end of the first quarter of 2022 was approximately US$1.72 billion. Once the Corporation's net debt balance reaches US$1.7 billion the Corporation will allocate approximately 25% of free cash flow generated to share buybacks with the remaining free cash flow applied to ongoing debt reduction until the Corporation's net debt balance reaches US$1.2 billion. In the current commodity price environment MEG expects to reach its US$1.2 billion net debt target in the third quarter of 2022.

Once the US$1.2 billion net debt target is reached the Corporation intends to increase the percentage of free cash flow allocated to share buybacks to approximately 50% with the remainder applied to further debt reduction until the Corporation reaches its net debt floor of US$600 million at which time 100% of free cash flow will be returned to shareholders. At current production levels, this net debt floor implies a net debt to EBITDA multiple of approximately 1.0 times at a long-term US$50 per barrel WTI price. In the current commodity price environment the Corporation expects to reach its net debt floor in the second half of 2023.

On March 16, 2022, the Corporation announced the planned retirement of its Chief Financial Officer effective September 1, 2022. MEG is conducting an external search for its next Chief Financial Officer and will provide an update upon successful completion of this search.

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

	2022	2021				2020		
($millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Bitumen production - bbls/d	**101,128**	100,698	91,506	91,803	90,842	91,030	71,516	75,687
Steam-oil ratio	**2.43**	2.42	2.56	2.39	2.37	2.31	2.36	2.32
Bitumen sales - bbls/d	**100,186**	98,894	92,251	89,980	87,298	95,731	67,569	70,397
Bitumen realization(1) - $/bbl	**97.28**	71.06	64.91	60.09	52.34	38.64	39.68	10.18
Operating expenses net of power revenue(1) - $/bbl	**8.98**	8.20	7.17	5.54	5.25	6.98	6.05	6.14
Non-energy operating costs(2) - $/bbl	**4.74**	4.56	4.46	3.84	4.05	4.70	3.96	4.09
Cash operating netback(1) - $/bbl	**70.21**	37.87	37.31	31.30	26.03	18.66	16.58	25.84
General & administrative expense - $/bbl of bitumen production volumes	**1.61**	1.58	1.72	1.56	1.77	1.65	1.50	1.29
Funds flow from operating activities	**587**	260	212	160	121	81	19	69
Adjusted funds flow(3)	**587**	266	239	166	127	84	26	89
Per share, diluted	**1.87**	0.85	0.77	0.53	0.41	0.27	0.09	0.29
Revenues	**1,531**	1,307	1,091	1,009	914	786	533	307
Net earnings (loss)	**362**	177	54	68	(17)	16	(9)	(80)
Per share, diluted	**1.15**	0.57	0.17	0.22	(0.06)	0.05	(0.03)	(0.26)
Capital expenditures	**88**	106	84	71	70	40	35	20
Net debt(3) - C$	**2,150**	2,401	2,559	2,661	2,798	2,798	2,981	2,976
Net debt(3) - US$	**1,722**	1,897	2,007	2,145	2,226	2,194	2,237	2,186

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

3. SUSTAINABILITY

On April 7, 2022 the Canadian federal government announced an investment tax credit for carbon capture, utilization and storage projects for industries across Canada. MEG believes this announcement is a positive step in the Oilsands Pathways to Net Zero ("Pathways") Alliance's efforts to work collaboratively with governments to help Canada achieve its climate goals and ensure our country can be the world's preferred supplier of responsibly-produced oil. The Pathways Alliance anticipates that this tax credit, together with support from the Alberta government, will help advance the Pathways Alliance unprecedented plan to achieve meaningful emissions reductions by 2030 and ultimately the goal of net zero emissions from oil sands operations by 2050.

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

4. NET EARNINGS (LOSS)

		Three months ended March 31		
($millions, except per share amounts)		**2022**		**2021**
Net earnings (loss)	**$**	**362**	$	(17)
Per share, diluted	**$**	**1.15**	$	(0.06)

Increased net earnings during the three months ended March 31, 2022 was primarily due to stronger global crude oil prices. The net loss during the three months ended March 31, 2021 was impacted by losses on commodity risk management.

5. REVENUES

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

		Three months ended March 31		
($millions)		**2022**		**2021**
Sales from:				
Production	**$**	**1,393**	$	695
Purchased product[1]		**161**		198
Petroleum revenue	**$**	**1,554**	$	893
Royalties		**(47)**		(7)
Petroleum revenue, net of royalties	**$**	**1,507**	$	886
Power revenue	**$**	**23**	$	25
Transportation revenue		**1**		3
Other revenue	**$**	**24**	$	28
Revenues	**$**	**1,531**	$	914

(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, 2022, revenues increased 67% from the same period of 2021 primarily as a result of the increase in the average blend sales price which was mostly driven by the increase in WTI prices.

6. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended March 31	
	2022	**2021**
Bitumen production – bbls/d	**101,128**	90,842
Steam-oil ratio (SOR)	**2.43**	2.37

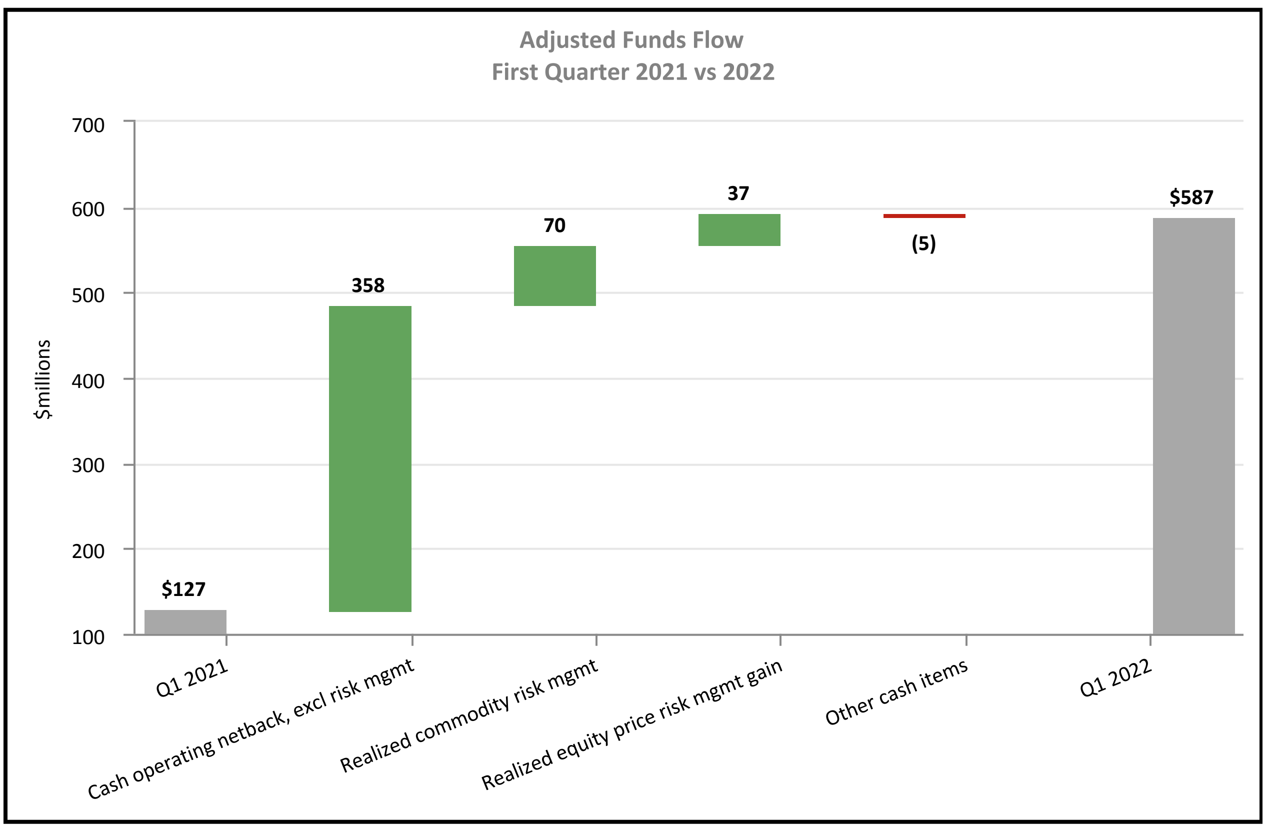
Bitumen Production

Bitumen production increased 11% during the three months ended March 31, 2022 compared to the same period of 2021. Increased steam utilization and ongoing optimization and recompletion work all contributed to strong field-wide production performance to date in 2022. Also contributing to the increase was the Corporation's commitment in the last half of 2021 to increase spending on incremental well capital aimed at fully utilizing the 100,000 barrels per day processing capacity of the Christina Lake plant.

Steam-Oil Ratio

The Corporation uses SAGD technology to recover bitumen. In SAGD operations, steam is injected into the oil reservoir to mobilize bitumen, which is then pumped to the surface. An important metric for thermal oil projects is Steam-Oil Ratio ("SOR"), which is an efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR increased for the three months ended March 31, 2022, compared to the same period of 2021, due to the timing of new well pairs converted to SAGD.

Funds Flow from Operating Activities and Adjusted Funds Flow



During the three months ended March 31, 2022, funds flow from operating activities and adjusted funds flow increased compared to the same period of 2021. The increase was primarily driven by the Corporation's increased cash operating netback, which was primarily impacted by an increase in global crude oil prices.

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

	Three months ended March 31	
($millions)	**2022**	**2021**
Funds flow from operating activities	**$ 587**	$ 121
Adjustments:		
Payments on onerous contract	**—**	6
Adjusted funds flow[1]	**$ 587**	$ 127
Adjusted funds flow per share - diluted	**$ 1.87**	$ 0.41

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

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

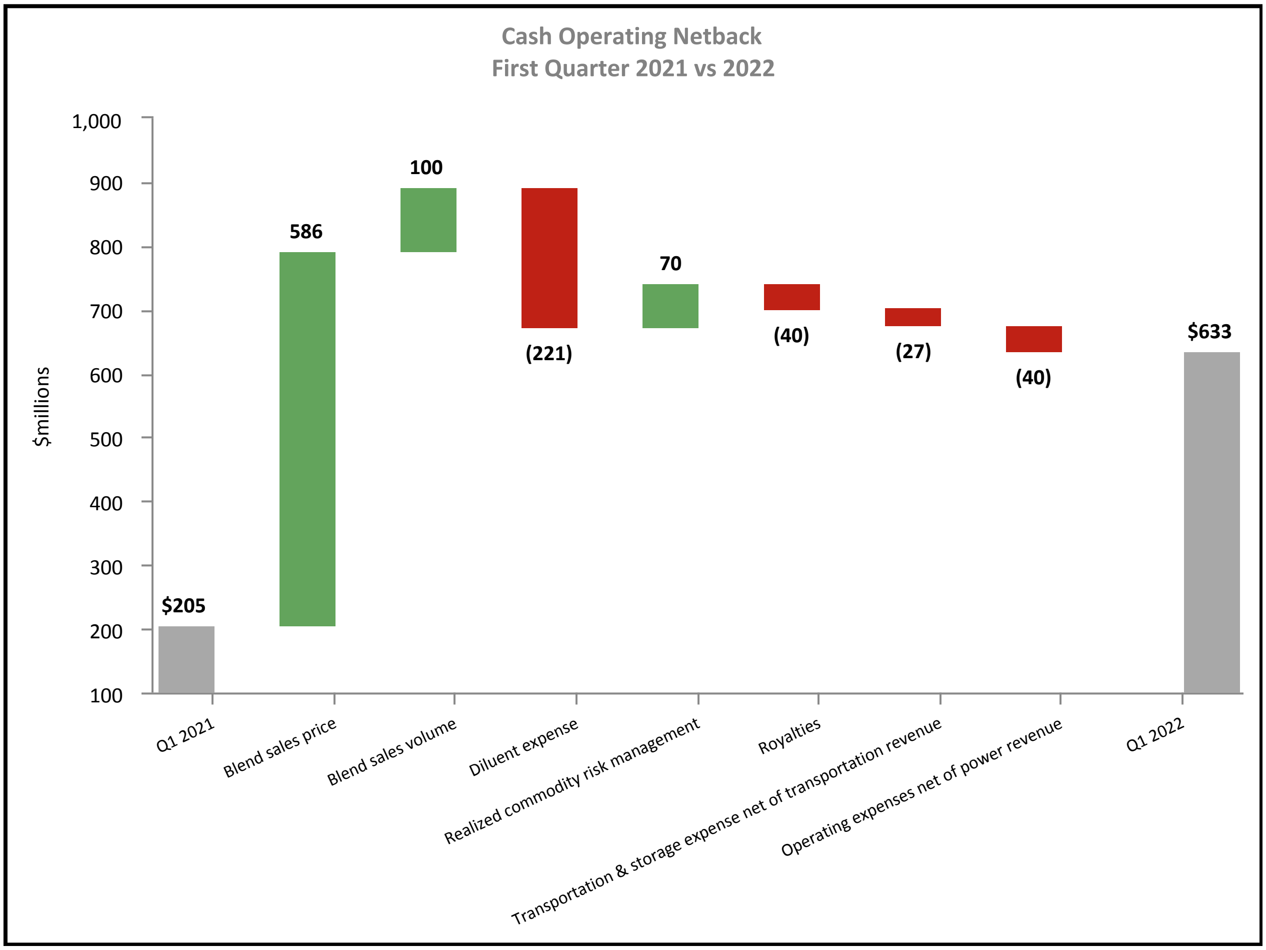
Cash Operating Netback

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			
	2022		**2021**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Sales from production	**$ 1,393**		$ 695	
Sales from purchased product[1]	**161**		198	
Petroleum revenue	**1,554**		893	
Purchased product[1]	**(160)**		(185)	
Blend sales[2][3]	**$ 1,394**	**$ 105.79**	$ 708	$ 61.28
Diluent expense	**(517)**	**(8.51)**	(296)	(8.94)
Bitumen realization[3]	**877**	**97.28**	412	52.34
Transportation and storage expense net of transportation revenue[3][4]	**(117)**	**(12.97)**	(90)	(11.41)
Royalties	**(47)**	**(5.24)**	(7)	(0.85)
Operating expenses net of power revenue[3]	**(81)**	**(8.98)**	(41)	(5.25)
Cash operating netback before realized commodity risk management	**632**	**70.09**	274	34.83
Realized gain (loss) on commodity risk management	**1**	**0.12**	(69)	(8.80)
Cash operating netback[3]	**$ 633**	**$ 70.21**	$ 205	$ 26.03
Bitumen sales volumes - bbls/d		**100,186**		87,298

(1) Sales and purchases of oil products related to marketing asset optimization activities.
(2) Blend sales per barrel are based on blend sales volumes.
(3) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.
(4) Transportation and storage expense net of transportation revenue includes costs associated with moving and storing blended barrels to optimize the timing of delivery, net of third-party recoveries on diluent transportation arrangements.

Blend sales includes sales from purchased product net of the cost of purchased product related to marketing asset optimization activities undertaken in the period. Marketing asset optimization is focused on the recovery of fixed costs related to transportation and storage contracts during periods of underutilization of these assets, with the goal to strengthen cash operating netback. Marketing asset optimization activities consist of the purchase and sale of third-party products. The Corporation does not engage in speculative trading. The purchase and sale of third-party products to facilitate asset optimization activities requires the elimination of price risk pursuant to policies approved by the Corporation's Board of Directors which can be achieved either through the counterparty or through financial price risk management.



Bitumen Realization

Bitumen realization represents the Corporation's blend sales less the cost of diluent, expressed on a per barrel of bitumen sold basis. Blend sales represents the Corporation's revenue from its oil blend known as AWB, which is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. Also included in blend sales are net profits from third-party purchases and sales associated with asset optimization activities. The cost of diluent is impacted by Canadian and U.S. benchmark pricing, the amount of diluent required which is impacted by seasonality and pipeline specifications, the cost of transporting diluent to the production site from both Edmonton and U.S. Gulf Coast ("USGC") markets, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar. The cost of diluent purchased is partially offset by the sales of such diluent in blend volumes. Bitumen realization per barrel fluctuates primarily based on average benchmark prices and light:heavy oil differentials.

	Three months ended March 31			
	2022		2021	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	**$ 1,393**		$ 695	
Sales from purchased product[1]	**161**		198	
Petroleum revenue	**$ 1,554**		$ 893	
Purchased product[1]	**(160)**		(185)	
Blend sales[2][3]	**$ 1,394**	**$ 105.79**	$ 708	$ 61.28
Diluent expense	**(517)**	**(8.51)**	(296)	(8.94)
Bitumen realization[3]	**$ 877**	**$ 97.28**	$ 412	$ 52.34

(1) Sales and purchases of oil products related to marketing asset optimization activities.
(2) Blend sales per barrel are based on blend sales volumes.
(3) Non-GAAP financial measure - please refer to section 14 "Non-GAAP and Other Financial Measures" of this MD&A.

Blend sales price increased by $44.51 per barrel, or 73%, during the three months ended March 31, 2022 compared to the same period of 2021. The increase in blend sales price during the three months ended March 31, 2022 is primarily due to a higher WTI price. During the three months ended March 31, 2022, the Corporation sold 58% of its blend sales volumes via pipeline at the USGC compared to 38% in the same period of 2021. Apportionment levels averaged 10% during the three months ended March 31, 2022 compared to 48% in the same period of 2021.

Diluent expense per barrel represents the cost of diluent that is unrecovered through blended sales. The diluent expense per barrel during the three months ended March 31, 2022 was in line with the same period of 2021 as the WTI:WCS differentials were similar in each period.

Total diluent expense was $517 million during the three months ended March 31, 2022 compared to $296 million during the same period of 2021. This translates to a cost per barrel of diluent during the three months ended March 31, 2022 of $124.23 compared to $80.34 for the same period of 2021. The cost per barrel is impacted by the benchmark condensate price, transportation costs to move diluent to the Christina Lake production site and the timing of use of inventory. The cost of diluent recognized is determined on a weighted-average cost basis and diluent volumes are typically held in inventory for 30 to 60 days. Approximately half of the diluent is sourced from each of Edmonton and Mont Belvieu, Texas. Refer to condensate prices within the "BUSINESS ENVIRONMENT" section of this MD&A for further details.

Transportation and Storage Expense net of Transportation Revenue

The Corporation's marketing strategy focuses 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.

	Three months ended March 31			
	2022		2021	
($millions, except as indicated)		$/bbl		$/bbl
Transportation and storage expense	**$ (118)**	**$ (13.12)**	$ (93)	$ (11.83)
Transportation revenue	**1**	**0.15**	3	0.42
Transportation and storage expense net of transportation revenue	**$ (117)**	**$ (12.97)**	$ (90)	$ (11.41)
Bitumen sales volumes - bbls/d		**100,186**		87,298

During the three months ended March 31, 2022, transportation and storage expense net of transportation revenue, on a total basis and a per barrel basis, increased compared to the same period of 2021. Due to low apportionment levels during the three months ended March 31, 2022, the Corporation was able to ship more volumes to the higher priced USGC market in this period which primarily drove the increase in transportation costs compared to the same period of 2021.

The Corporation partially mitigated the cost of unutilized transportation and storage assets through the purchase and sale of non-proprietary product, or asset optimization activities, which added $1 million, or $0.04 per barrel to blend sales, during the three months ended March 31, 2022 compared to $13 million, or $1.07 per barrel to blend sales, during the same period of 2021. After considering the impact of asset optimization activities, transportation and storage expense net of transportation revenue was $12.93 per barrel during the three months ended March 31, 2022 compared to $10.34 per barrel during the same period of 2021. Compared to the same period of 2021, the Corporation moved more proprietary barrels to the USGC and asset optimization activities declined.

Royalties

The oil sands royalty framework under the Oil Sands Royalty Regulation, 2009, establishes royalty rates for bitumen that are linked to price. The Alberta oil sands royalty payable is based on these price-sensitive royalty rates and applied to production volumes. The applicable royalty rates change depending on whether the project's status is pre-payout or post-payout. "Payout" is generally defined as the point in time when a project has generated enough net revenue to recover its costs and provide a designated return allowance. When a project reaches payout, its cumulative revenue equals or exceeds its cumulative costs. Costs include specified allowed capital and operating costs pursuant to the Oil Sands Allowed Costs (Ministerial) Regulation. The royalty payable for pre-payout projects is based on the project’s gross revenue multiplied by a gross revenue royalty rate. The gross revenue royalty rate starts at 1% and increases for every dollar that the world oil price, as reflected by the WTI crude oil price in Canadian dollars, is priced above $55 per barrel, to a maximum of 9% when the WTI crude oil price is $120 per barrel or higher. The royalty payable for post-payout projects is the greater of (i) the gross revenue royalty; or (ii) the net revenue royalty based on the net revenue royalty rate. The net revenue royalty rate is based on a formula which starts at 25% and increases for every dollar the WTI crude oil price is above $55 per barrel to a maximum of 40% when the WTI crude oil price is $120 per barrel or higher.

The Corporation’s Christina Lake operation is currently in pre-payout and the applicable royalty rate is applied to gross revenues for royalty purposes.

	Three months ended March 31			
	2022		**2021**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Royalties	**$ (47)**	**$ (5.24)**	$ (7)	$ (0.85)

The WTI benchmark price increased 63% during the three months ended March 31, 2022, compared to the same period of 2021, which increased the gross royalty rate applied from 2% to 7%.

Operating Expenses net of Power Revenue

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

	Three months ended March 31			
	2022		2021	
($millions, except as indicated)		$/bbl		$/bbl
Non-energy operating costs[1]	**$ (43)**	**$ (4.74)**	$ (32)	$ (4.05)
Energy operating costs[1]	**(61)**	**(6.80)**	(34)	(4.34)
Power revenue	**23**	**2.56**	25	3.14
Operating expenses net of power revenue[2]	**$ (81)**	**$ (8.98)**	$ (41)	$ (5.25)
Average natural gas purchase price (C$/mcf)		**$ 5.35**		$ 3.62
Average realized power sales price (C$/Mwh)		**$ 91.50**		$ 93.27

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

Total non-energy operating costs and non-energy operating costs per barrel have increased for the three months ended March 31, 2022, compared to the same period of 2021. The increase is primarily due to increased staff costs, increased well workovers, higher priced chemicals and increased overall maintenance activity.

Energy operating costs increased predominantly due to the AECO natural gas market strengthening by approximately 50%, as well as increased consumption as production increased. Power revenue offset energy operating costs by 38% during the three months ended March 31, 2022 compared to 74% during the same period of 2021. Power revenue during the first quarter of 2021 included the impact of physical risk management contracts on power sales. The Alberta power market weakened by 7% during the three months ended March 31, 2022 compared to the same period of 2021.

Realized Gain or Loss on Commodity Risk Management

From time to time, the Corporation enters into financial commodity risk management contracts. The Corporation has not entered into any WTI or WTI:WCS differential commodity risk management contracts for 2022. Realized gains on commodity risk management contracts were recognized during the three months ended March 31, 2022 associated with fixed natural gas purchase contracts in place. During the same period of 2021, the Corporation held crude oil, natural gas and condensate commodity risk management contracts. The realized loss recognized during this period primarily relates to a strengthening WTI price compared to WTI fixed price contracts in place. Refer to the commodity risk management discussion within the “OTHER OPERATING RESULTS” section of this MD&A for further details.

	Three months ended March 31			
	2022		2021	
($millions, except as indicated)		$/bbl		$/bbl
Realized gain (loss) on commodity risk management	**$ 1**	**$ 0.12**	$ (69)	$ (8.80)

Capital Expenditures

	Three months ended March 31	
($millions)	2022	2021
Sustaining and maintenance	**$ 80**	$ 65
Phase 2B brownfield expansion	**—**	4
Field infrastructure, corporate and other	**8**	1
	$ 88	$ 70

The majority of the $88 million invested in the three months ended March 31, 2022 was directed towards sustaining and maintenance activities which includes incremental capital to allow the Corporation to fully utilize the Christina Lake central plant facility's oil processing capacity of approximately 100,000 barrels per day, prior to any impact from scheduled maintenance activity or outages.

7. OUTLOOK

On November 29, 2021 the Corporation released its 2022 capital and operating budget.

The Corporation's 2022 production and operational guidance remains unchanged from the budget and reflects the impact of a scheduled 30-day turnaround in the second quarter at its Christina Lake Phase 2B facility which is expected to impact full year production by approximately 6,000 barrels per day.

The Corporation has capacity to ship 100,000 barrels per day of AWB blend sales, on a pre-apportionment basis, to the USGC market via its committed capacity on the Flanagan South and Seaway pipeline systems ("FSP"). The Corporation expects to sell approximately two-thirds of its full year 2022 AWB blend sales volumes into the USGC via FSP with the remainder being sold into the Edmonton market. The Corporation expects full year 2022 total transportation costs to average between US$7.50 and US$8.00 per barrel of AWB blend sales.

The Corporation has not entered into any WTI or WTI:WCS differential commodity risk management contracts for 2022.

Summary of 2022 Guidance(1)	
Bitumen production - annual average	94,000 - 97,000 bbls/d
Non-energy operating costs	$4.50 - $4.80 per bbl
G&A expense	$1.70 - $1.85 per bbl
Capital expenditures	$375 million

(1) 2022 guidance includes the impact of a scheduled 30-day turnaround at the Corporation's Christina Lake Phase 2B facility 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	2022	2021				2020		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Crude oil prices								
Brent (US$/bbl)	**97.23**	79.78	73.15	68.98	61.06	45.25	43.39	33.30
WTI (US$/bbl)	**94.29**	77.19	70.56	66.07	57.84	42.66	40.93	27.85
Differential – WTI:WCS – Edmonton (US$/bbl)	**(14.53)**	(14.64)	(13.58)	(11.49)	(12.47)	(9.30)	(9.09)	(11.47)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(16.35)**	(16.40)	(15.13)	(13.11)	(14.22)	(10.56)	(10.48)	(13.44)
AWB – Edmonton (US$/bbl)	**77.94**	60.79	55.43	52.96	43.62	32.10	30.45	14.41
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(5.85)**	(6.40)	(5.57)	(3.92)	(2.52)	(2.83)	(3.20)	(7.29)
AWB – U.S. Gulf Coast (US$/bbl)	**88.44**	70.79	64.99	62.15	55.32	39.83	37.73	20.56
Enbridge Mainline heavy apportionment	**10 %**	21 %	53 %	46 %	48 %	22 %	9 %	13 %
Condensate prices								
Condensate at Edmonton (C$/bbl)	**121.74**	99.70	87.30	81.55	73.51	55.39	50.03	30.72
Condensate at Edmonton as % of WTI	**102.0 %**	102.5 %	98.2 %	100.5 %	100.4 %	99.6 %	91.8 %	79.6 %
Condensate at Mont Belvieu, Texas (US$/bbl)	**92.68**	76.62	68.19	61.18	56.00	38.52	33.52	17.43
Condensate at Mont Belvieu, Texas as a % of WTI	**98.3 %**	99.3 %	96.6 %	92.6 %	96.8 %	90.3 %	81.9 %	62.6 %
Natural gas prices								
AECO (C$/mcf)	**5.16**	5.07	3.92	3.37	3.43	2.88	2.48	2.21
Electric power prices								
Alberta power pool (C$/MWh)	**90.47**	107.25	100.27	104.73	97.25	46.05	43.75	29.94
Foreign exchange rates								
C$ equivalent of 1 US$ – average	**1.2661**	1.2600	1.2602	1.2280	1.2663	1.3031	1.3316	1.3860
C$ equivalent of 1 US$ – period end	**1.2484**	1.2656	1.2750	1.2405	1.2572	1.2755	1.3324	1.3616

Crude Oil Prices

Brent crude is the primary world price benchmark for global light sweet crude oil. The price of WTI is the current benchmark for mid-continent North American crude oil prices, at Cushing Oklahoma, and its Canadian dollar equivalent is the basis for determining the royalty rate on the Corporation's bitumen sales.

Global crude oil prices strengthened in the first quarter of 2022 as a result of improved demand and declining inventories. Supply uncertainty further supported higher global crude oil prices as the Russian invasion of Ukraine and subsequent sanctions against Russia created concern for significant oil supply disruption. Although some supply relief was provided in the latter part of the quarter with the announcement of a globally coordinated release from strategic petroleum reserves, supply and demand fundamentals remain tight with the OPEC+ group maintaining its planned production increases.

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

The Corporation sells AWB, an oil similar to WCS, but generally priced at a discount to the WCS benchmark at Edmonton, with the discount dependent on the quality difference between AWB and WCS and the supply/demand fundamentals for oil in Western Canada. AWB is also sold at the USGC and is sold at a discount or premium to WTI dependent on the supply/demand fundamentals for oil in the USGC region.

Condensate Prices

In order to facilitate pipeline transportation of bitumen, the Corporation uses condensate as diluent for blending with the Corporation's bitumen. The price of condensate generally correlates with the price of WTI. The Corporation sources its condensate from both the Edmonton area and the USGC, where pricing is generally lower. The Corporation has committed diluent purchases of 20,000 barrels per day at the USGC reference benchmark pricing at Mont Belvieu, Texas. Generally, condensate pricing strengthened along with the broader strengthening in petroleum pricing during the first quarter of 2022.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, used as fuel to generate steam for the thermal production process and to create steam and electricity from the Corporation's cogeneration facilities. Global natural gas prices have surged during the last six months after lower availability of renewable wind power in the summer of 2021, the closure of nuclear plants in Germany and lower Russian exports led to increased reliance on natural gas, which resulted in record low storage levels. Russia's invasion of Ukraine has driven prices even higher due to Europe's reliance on natural gas from Russia. As a result, U.S. exports have surged to record levels on the back of strong international demand and surging prices. As a result, the AECO natural gas price increased approximately 50% during the three months ended March 31, 2022 compared to the same period of 2021.

Electric Power Prices

Electric power prices impact the price that the Corporation receives on the sale of surplus power from the Corporation's cogeneration facilities. The Alberta power pool price decreased slightly during the three months ended March 31, 2022 compared to the same period of 2021 primarily as a result of less extreme winter conditions.

9. OTHER OPERATING RESULTS

General and Administrative

	Three months ended March 31	
($millions, except as indicated)	**2022**	**2021**
General and administrative	**$ 14**	$ 14
General and administrative expense per barrel of production	**$ 1.61**	$ 1.77

G&A expense during the three months ended March 31, 2022 was in line with the same period of 2021.

Depletion and Depreciation

	Three months ended March 31	
($millions, except as indicated)	**2022**	**2021**
Depletion and depreciation expense	**$ 124**	$ 108
Depletion and depreciation expense per barrel of production	**$ 13.58**	$ 13.15

Total depletion and depreciation expense increased during the three months ended March 31, 2022, compared to the same period of 2021, primarily due to the increase in production as well as higher average future development costs.

Commodity Risk Management Gain (Loss), Net

From time to time, the Corporation enters into financial commodity risk management contracts to increase the predictability of the Corporation's cash flow by managing commodity price volatility. All financial commodity risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss). The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes.

Realized gains or losses on financial commodity risk management contracts are the result of contract settlements during the period. Unrealized gains or losses on financial commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.

The Corporation has not entered into any WTI or WTI:WCS differential commodity risk management contracts for 2022.

	Three months ended March 31	
($millions)	**2022**	**2021**
Realized gain (loss) on:		
Crude oil contracts[1]	**$ —**	$ (81)
Condensate contracts[2]	**—**	11
Natural gas contracts[3]	**1**	1
Realized commodity risk management gain (loss)	**$ 1**	$ (69)
Unrealized gain (loss) on:		
Crude oil contracts[1]	**$ —**	$ (86)
Condensate contracts[2]	**—**	(6)
Natural gas contracts[3]	**4**	4
Unrealized commodity risk management gain (loss)	**$ 4**	$ (88)
Commodity risk management gain (loss)	**$ 5**	$ (157)

(1) Includes WTI fixed price contracts, WTI enhanced fixed price contracts with sold put options and WTI:WCS fixed differential contracts.

(2) Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas relative to WTI.

(3) Relates to contracts which fix the AECO price on natural gas purchases.

For the three months ended March 31, 2022, the Corporation recognized a $5 million net gain from commodity risk management compared to a $157 million net loss from commodity risk management during the same period of 2021 primarily due to the fact that the Corporation no longer holds any crude oil commodity risk management contracts.

The realized commodity risk management gain (loss) represents actual contract settlements over the periods presented. The following table provides further details regarding the realized commodity risk management gain (loss):

	Three months ended March 31	
(US$/bbl)	**2022**	**2021**
WTI fixed price contracts[1][2]:		
Average fixed price	**$ —**	$ 46.96
Average settlement price	**—**	57.82
Gain (loss) on WTI fixed price contracts	**$ —**	$ (10.86)
WTI:WCS fixed differential contracts:		
Average fixed differential	**$ —**	$ (13.46)
Average settlement differential	**—**	(11.46)
Gain (loss) on WTI:WCS fixed differential contracts	**$ —**	$ (2.00)
Condensate purchase contracts:		
Average fixed differential[3]	**$ (11.30)**	$ (10.37)
Average settlement differential	**(1.61)**	(1.84)
Gain (loss) on condensate purchase contracts	**$ 9.69**	$ 8.53
(C$/GJ)		
Natural gas purchase contracts:		
Average fixed price	**$ 2.50**	$ 2.61
Average settlement price	**4.49**	2.95
Gain (loss) on natural gas purchase contracts	**$ 1.99**	$ 0.34

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

(2) Incremental to these WTI fixed price contracts, the Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months, the gains and losses on which are not reflected in this table.

(3) Condensate purchase contracts either fix the WTI:condensate differential at Mont Belvieu, Texas relative to WTI or fix the condensate price as a % of WTI.

Stock-based Compensation

	Three months ended March 31	
($millions)	**2022**	**2021**
Cash-settled expense	**$ 44**	$ 19
Equity-settled expense	**4**	2
Equity price risk management gain[1]	**(42)**	(19)
Stock-based compensation expense (recovery)	**$ 6**	$ 2

(1) Relates to financial derivatives entered into to manage the Corporation's exposure to cash-settled restricted share units ("RSUs") and performance share units ("PSUs") vesting in 2021, 2022 and 2023 granted under the Corporation's stock-based compensation plans. Amounts are unrealized until vesting of the related units occurs. See section 11 "Risk Management" of this MD&A for further details.

The increase in cash-settled expense was primarily due to the increase in the Corporation's share price. The Corporation's common share price increased to $17.07 per share as at March 31, 2022, from its value of $11.70 per share as at December 31, 2021.

The equity price risk management gain is driven by the change in the Corporation's common share price relative to the notional value of the instruments. For the three months ended March 31, 2022, an equity price risk management gain of $42 million was recognized on the increase in share price during the period compared to a gain of $19 million during the same period of 2021.

Foreign Exchange Gain (Loss), Net

	Three months ended March 31	
($millions)	**2022**	**2021**
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ 31**	$ 48
Foreign currency risk management contracts	**7**	—
US$ denominated cash and cash equivalents	**(9)**	(5)
Unrealized net gain (loss) on foreign exchange	**29**	43
Realized gain (loss) on foreign exchange	**(1)**	—
Foreign exchange gain (loss), net	**$ 28**	$ 43

C$ equivalent of 1 US$		
Beginning of period	**1.2656**	1.2755
End of period	**1.2484**	1.2572

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

For the three months ended March 31, 2022, the Corporation recognized an unrealized foreign exchange gain of $29 million compared to a gain of $43 million during the same period of 2021. The Canadian dollar strengthened relative to the U.S. dollar by 1% during both periods but the unrealized gain during the three months ended March 31, 2022 was lower compared to the same period of 2021 primarily due to the decrease in U.S. dollar denominated long-term debt.

Net Finance Expense

	Three months ended March 31	
($millions)	**2022**	**2021**
Interest expense on long-term debt	**$ 47**	$ 58
Interest expense on lease liabilities	**6**	6
Net interest expense	**53**	64
Accretion on provisions	**2**	2
Net finance expense	**$ 55**	$ 66

Average effective interest rate	**6.7%**	6.8%

Interest expense on long-term debt decreased during the three months ended March 31, 2022 compared to the same period of 2021 primarily as a result of the US$100 million debt redemption on August 23, 2021 and the US$225 million debt redemption on January 18, 2022 as well as the refinancing of US$600 million of senior unsecured notes on February 2, 2021 at a rate of 5.875% compared to the previous rate of 7.0%.

Income Tax

	Three months ended March 31	
($millions)	2022	2021
Earnings (loss) before income taxes	**$ 466**	$ (36)
Effective tax rate	**22.3 %**	52.8 %
Income tax expense (recovery)	**$ 104**	$ (19)

As at March 31, 2022, the Corporation had approximately $6.7 billion of available Canadian tax pools, including $5.1 billion of non-capital losses and $0.4 billion of capital losses, and recognized a deferred income tax asset of $192 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

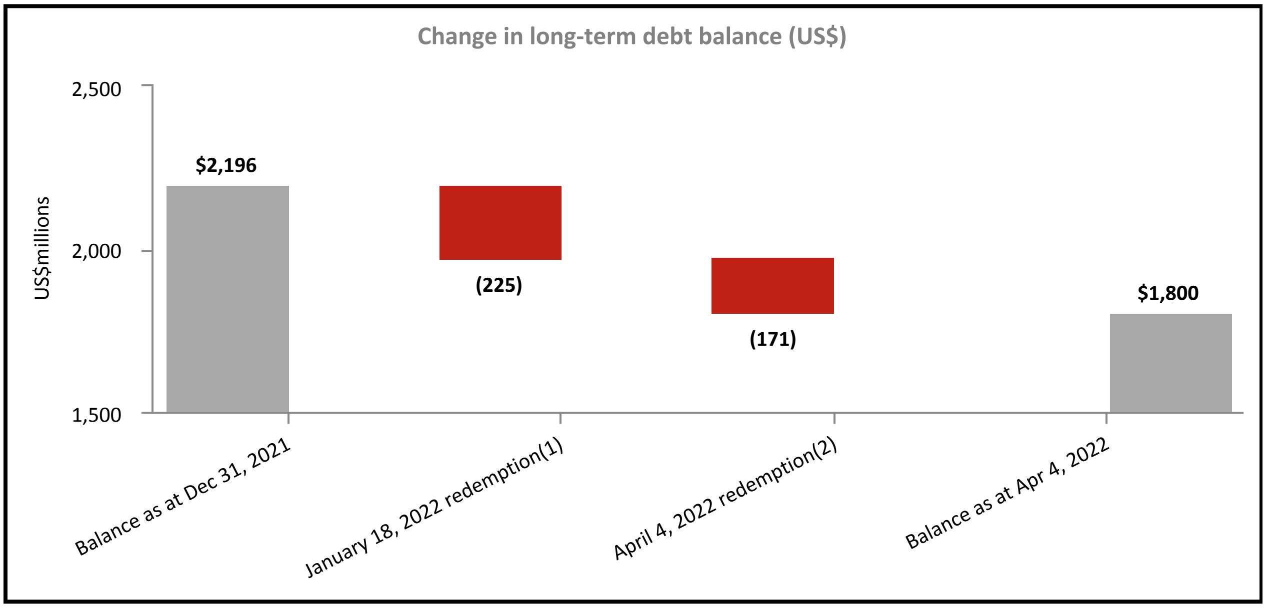
The effective tax rate for the three months ended March 31, 2022 differed from the Canadian statutory rate of 23% primarily due to the tax effect of foreign exchange gains and losses on the Corporation's long-term debt which is denominated in U.S. dollars.

10. LIQUIDITY AND CAPITAL RESOURCES

($millions)	March 31, 2022	December 31, 2021
Second Lien:		
6.50% senior secured second lien notes (March 31, 2022 - US$171 million; fully redeemed April 4, 2022; December 31, 2021 - US$396 million)	**$ 214**	$ 501
Unsecured:		
7.125% senior unsecured notes (March 31, 2022 - US$1.2 billion; due 2027; December 31, 2021 - US$1.2 billion)	**1,498**	1,519
5.875% senior unsecured notes (March 31, 2022 - US$600 million; due 2029; December 31, 2021 - US$600 million)	**749**	759
Debt redemption premium	**4**	8
Unamortized deferred debt discount and debt issue costs	**(25)**	(25)
Current and long-term debt	**2,440**	2,762
Cash and cash equivalents	**(290)**	(361)
Net debt - C$[1]	**$ 2,150**	$ 2,401
Net debt - US$[1]	**$ 1,722**	$ 1,897

(1) Net debt is reconciled to long-term debt in accordance with IFRS in Note 18 of the interim consolidated financial statements.

The Corporation redeemed and announced further redemptions of its long-term debt as noted below:



(1) Redemption price of 101.625% plus accrued and unpaid interest on the 6.50% senior secured second lien notes.
(2) Redemption price of 101.625% plus accrued and unpaid interest on the remaining 6.50% senior secured second lien notes.

The Corporation's cash and cash equivalents balance was $290 million as at March 31, 2022 compared to $361 million as at December 31, 2021. Refer to the "Cash Flow Summary" section for further details.

The Corporation has total available credit under two facilities of $1.3 billion, comprised of $800 million under the revolving credit facility and $500 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 a maturity date of July 30, 2024. The revolving credit facility, EDC Facility and senior secured second lien notes are secured by substantially all the assets of the Corporation.

Meeting current and future obligations while navigating the uncertainty associated with commodity market volatility continues to be supported by the Corporation's financial framework, including credit risk management policies minimizing credit exposure on sales to primarily investment grade customers in the energy industry. After the April 2022 debt redemption noted above, the Corporation's earliest maturing long-term debt is approximately five years out, represented by US$1.2 billion of senior unsecured notes due February 2027. Additionally, the Corporation's modified covenant-lite $800 million revolving credit facility has no financial maintenance covenant unless drawn in excess of $400 million. If drawn in excess of $400 million, the Corporation is required to maintain a quarterly first lien net leverage ratio (first lien net debt to last twelve-month EBITDA) of 3.5 or less. Under the Corporation's credit facility, first lien net debt is calculated as debt under the credit facility plus other debt that is secured on a pari passu basis with the credit facility, less cash-on-hand. None of the Corporation's outstanding long-term debt contain financial maintenance covenants and none are secured on a *pari passu* basis with the credit facility.

As at March 31, 2022, the Corporation had $794 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $108 million of unutilized capacity under the $500 million EDC Facility. A letter of credit of $15 million was issued under the revolving credit facility during the three months ended March 31, 2020. A letter of credit of $6 million remains outstanding under the revolving credit facility as at March 31, 2022. Letters of credit issued under the revolving credit facility are not included in first lien net debt for purposes of calculating the first lien net leverage ratio.

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary. The Corporation's cash flow and the development of projects are dependent on factors discussed in the "RISK FACTORS" section of this MD&A.

Cash Flow Summary

	Three months ended March 31	
($millions)	**2022**	**2021**
Net cash provided by (used in):		
Operating activities	**$ 317**	$ 12
Investing activities	**(88)**	(49)
Financing activities	**(291)**	(17)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(9)**	(6)
Change in cash and cash equivalents	**$ (71)**	$ (60)

Cash Flow – Operating Activities

Net cash provided by operating activities for the three months ended March 31, 2022 increased compared to the same period of 2021, primarily due to higher benchmark crude oil prices as well as the elimination of crude oil commodity risk management contracts that were in place in the first quarter of 2021.

Cash Flow – Investing Activities

Net cash used in investing activities increased during the three months ended March 31, 2022 compared to the same period of 2021 reflecting increased capital spending over the period.

Cash Flow – Financing Activities

Net cash used in financing activities for the three months ended March 31, 2022 increased compared to the same period of 2021, primarily due to the debt redemption during the three months ended March 31, 2022.

11. RISK MANAGEMENT

Commodity Price Risk Management

To mitigate the Corporation's exposure to fluctuations in commodity prices, the Corporation periodically enters into financial commodity risk management contracts to partially manage its exposure on blend sales, condensate purchases, natural gas purchases and power sales. The Corporation also periodically enters into physical delivery contracts which are not considered financial instruments and therefore no asset or liability has been recognized in the Consolidated Balance Sheet related to these contracts. The impact of realized physical delivery contract prices is included in the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss) and in cash operating netback.

The Corporation had the following financial commodity risk management contracts relating to condensate purchases and natural gas purchases outstanding as at March 31, 2022:

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

Equity Price Risk Management

In 2020, the Corporation entered into financial equity price risk management contracts to increase the predictability of the Corporation's cash flow by managing share price volatility. Equity price risk is the risk that changes in the Corporation's own share price impact earnings and cash flows. Earnings, funds flow from operating activities and adjusted funds flow are impacted when outstanding cash-settled RSUs and PSUs, issued under the Corporation's stock-based compensation plans, are revalued each period based on the Corporation's share price and the revaluation is recognized in stock-based compensation expense. Net cash provided by (used in) operating activities is impacted when these stock-based compensation units are ultimately settled. The Corporation entered into these equity price risk management contracts in March 2020 to manage its exposure on cash-settled RSUs and PSUs vesting between April 1, 2021 and April 1, 2023. Equity price risk management (gain) loss is recognized in stock-based compensation expense on the statement of earnings (loss), the unrealized asset (liability) is included in risk management on the balance sheet and the realized asset is included in trade receivables and other on the balance sheet.

	Three months ended March 31	
($millions)	**2022**	**2021**
Unrealized equity price risk management (gain) loss	**$ 4**	$ (11)
Realized equity price risk management (gain) loss	**(46)**	(8)
Equity price risk management (gain) loss	**$ (42)**	$ (19)

12. SHARES OUTSTANDING

As at March 31, 2022, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	**Units**
Common shares	**307.6**
Convertible securities	
Stock options(1)	**1.6**
Equity-settled RSUs and PSUs	**6.7**

(1) 1.4 million stock options were exercisable as at March 31, 2022.

As at April 29, 2022, the Corporation had 310.6 million common shares, 1.5 million stock options and 5.2 million equity-settled RSUs and equity-settled PSUs outstanding, and 1.5 million stock options exercisable.

13. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations as at March 31, 2022. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities, the senior secured second lien notes, and the senior unsecured notes may be retired earlier due to mandatory or discretionary repayments or redemptions.

($millions)	2022	2023	2024	2025	2026	Thereafter	Total
Commitments:							
Transportation and storage[1]	$ 302	$ 413	$ 440	$ 416	$ 378	$ 5,401	$ 7,350
Diluent purchases	130	28	—	—	—	—	158
Other operating commitments	12	16	14	13	13	23	91
Variable office lease costs	3	5	5	5	5	22	45
Capital commitments	21	—	—	—	—	—	21
Total Commitments	468	462	459	434	396	5,446	7,665
Other Obligations:							
Lease obligations	33	38	37	29	29	462	628
Current and long-term debt[2]	214	—	—	—	—	2,247	2,461
Interest on long-term debt[2]	113	151	151	151	151	106	823
Decommissioning obligation[3]	3	6	5	5	5	763	787
Total Commitments and Obligations	**$ 831**	**$ 657**	**$ 652**	**$ 619**	**$ 581**	**$ 9,024**	**$ 12,364**

(1) This represents transportation and storage commitments from 2022 to 2048, including pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet.

(2) This represents the scheduled principal repayments of the senior secured second lien notes, the senior unsecured notes, and associated interest payments based on interest and foreign exchange rates in effect on March 31, 2022.

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

Contingencies

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

14. NON-GAAP AND OTHER FINANCIAL MEASURES

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

Adjusted Funds Flow and Free Cash Flow

Adjusted funds flow and free cash flow are capital management measures and are defined in the Corporation's annual 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 changes in non-recurring adjustments from cash flows, 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 the cash operating netback. Free cash flow is presented to assist management and investors in analyzing performance by the Corporation as a measure of financial liquidity and the capacity of the business to repay debt and return capital to shareholders. Free cash flow is calculated as adjusted funds flow less capital expenditures.

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

	Three months ended March 31	
($millions)	**2022**	**2021**
Funds flow from operating activities	**$ 587**	$ 121
Adjustments:		
Payments on onerous contract	**—**	6
Adjusted funds flow	**587**	127
Capital expenditures	**(88)**	(70)
Free cash flow	**$ 499**	$ 57

Net Debt

Net debt is a capital management measure and is defined in the Corporation's annual 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, 2022**	**December 31, 2021**
Long-term debt	**$ 2,226**	$ 2,477
Current portion of long-term debt	**214**	285
Cash and cash equivalents	**(290)**	(361)
Net debt - C$	**$ 2,150**	$ 2,401
Net debt - US$	**$ 1,722**	$ 1,897

Cash Operating Netback

Cash operating netback is a non-GAAP financial measure, or ratio when expressed on a per barrel basis. Its terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. This non-GAAP financial measure should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Cash operating netback is a financial measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to generate cash flow for debt repayment, capital expenditures, or other uses. The per barrel calculation of cash operating netback is based on bitumen sales volume.

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

	Three months ended March 31	
($millions)	**2022**	**2021**
Revenues	**$ 1,531**	$ 914
Diluent expense	**(517)**	(296)
Transportation and storage expense	**(118)**	(93)
Purchased product	**(160)**	(185)
Operating expenses	**(104)**	(66)
Cash operating netback before realized commodity risk management	**632**	274
Realized gain (loss) on commodity risk management	**1**	(69)
Cash operating netback	**$ 633**	$ 205

Blend Sales and Bitumen Realization

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

Petroleum revenue, net of royalties, 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 petroleum revenue, net of royalties to blend sales and bitumen realization has been provided below:

	Three months ended March 31			
	2022		**2021**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Petroleum revenue, net of royalties	**$ 1,507**		$ 886	
Royalties	**47**		7	
Petroleum revenue	**1,554**		893	
Purchased product	**(160)**		(185)	
Blend sales	**1,394**	**$ 105.79**	708	$ 61.28
Diluent expense	**(517)**	**(8.51)**	(296)	(8.94)
Bitumen realization	**$ 877**	**$ 97.28**	$ 412	$ 52.34

Transportation and Storage Expense net of Transportation Revenue

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

It is used as a measure of the Corporation’s marketing strategy by focusing on maximizing the realized AWB sales price after transportation and storage expense by utilizing its network of pipeline and storage facilities to optimize market access. Per barrel amounts are based on bitumen sales volumes.

Transportation and storage expense, is an IFRS measure in the Corporation's consolidated statement of earnings (loss) and comprehensive income (loss).

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

	Three months ended March 31			
	2022		2021	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Transportation and storage expense	**$ (118)**	**$ (13.12)**	$ (93)	$ (11.83)
Other revenue	**$ 24**		$ 28	
Less power revenue	**(23)**		(25)	
Transportation revenue	**$ 1**	**$ 0.15**	$ 3	$ 0.42
Transportation and storage expense net of transportation revenue	**$ (117)**	**$ (12.97)**	$ (90)	$ (11.41)

Operating Expenses net of Power Revenue

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

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

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

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

	Three months ended March 31			
	2022		2021	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Non-energy operating costs	**$ (43)**	**$ (4.74)**	$ (34)	$ (4.05)
Energy operating costs	**(61)**	**(6.80)**	(32)	(4.34)
Operating expenses	**$ (104)**	**$ (11.54)**	$ (66)	$ (8.39)
Other revenue	**$ 24**		$ 28	
Less transportation revenue	**(1)**		(3)	
Power revenue	**$ 23**	**$ 2.56**	$ 25	$ 3.14
Operating expenses net of power revenue	**$ (81)**	**$ (8.98)**	$ (41)	$ (5.25)

15. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting policies and estimates are those estimates having a significant impact on the Corporation's financial position and operations and that require management to make judgments, assumptions and estimates in the application of IFRS. Judgments, assumptions and estimates are based on historical experience and other factors that management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgments, assumptions and estimates may be subject to change.

Detailed disclosure of the significant accounting policies and the significant accounting estimates, assumptions and judgments used by the Corporation can be found in the Corporation's annual consolidated financial statements for the year ended December 31, 2021.

16. RISK FACTORS

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

17. DISCLOSURE CONTROLS AND PROCEDURES

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

18. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

19. ABBREVIATIONS

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

Financial and Business Environment

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

Measurement

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

20. ADVISORY

Forward-Looking Information

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

Forward-looking statements are often, but not always, identified by such words. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. In particular, and without limiting the foregoing, this document contains forward looking statements with respect to: the Corporation's business strategy, focus and future plans; statements regarding the Corporation's estimated reserves; the Corporation's marketing strategy and marketing asset optimization strategy; the Corporation's ability to realize production growth over time at the Christina Lake Project while minimizing GHG emissions intensity through cogeneration and the application of its proprietary technologies; the ability of the Corporation to deliver on its deleveraging and shareholder return strategy; the Corporation's expectation of accelerating debt reduction and initiating its share buyback program in the second quarter of 2022; the Corporation's continued focus on debt reduction; statements regarding incremental well capital required to allow the Corporation to fully utilize the Christina Lake central plant facility's oil processing capacity of approximately 100,000 barrels per day the Corporation's 2022 guidance, including full year 2022 production, non-energy operating costs, general and administrative costs, capital expenditures and total transportation costs; the Corporation's expectation of reaching its near-term debt target of US$1.7 billion in the second quarter of 2022 and thereafter allocating 25% of free cash flow to share buybacks with the remaining cash flow applied to ongoing debt reduction; the Corporation's expectation of reaching its net debt-target of US$1.2 billion in the third quarter of 2022 and thereafter allocating 50% of free cash flow to share buybacks with the remainder applied to further debt reduction until the Corporation reaches its net debt floor of US$600 million at which time 100% of free cash flow will be returned to shareholders; the Corporation's expectation that net debt of US$600 million implies a net debt to EBITDA multiple of 1.0 times at a long-term US$50 per barrel WTI price; the Corporation's expectation that it will reach its net debt floor of US$600 in the second half of 2023; the Corporation's expectation that the announced federal investment tax credit, together with support from the Alberta government, will help advance the Oilsands Pathways to Net Zero Alliance's plan to achieve meaningful emissions reductions by 2023 and net zero emissions from oil sands operations by 2050; the Corporation's ability to sell excess power into the Alberta electrical grid to displace other power sources that have a higher carbon intensity, thereby reducing the Corporation's overall carbon footprint; the Corporation's expectations regarding its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business; and the Corporation's statements regarding its 2022 hedge book.

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

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

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

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

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

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

Estimates of Reserves and Resources

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

21. ADDITIONAL INFORMATION

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

22. QUARTERLY SUMMARIES

	2022	2021				2020		
Unaudited	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**362**	177	54	68	(17)	16	(9)	(80)
Per share, diluted	**1.15**	0.57	0.17	0.22	(0.06)	0.05	(0.03)	(0.26)
Funds flow from operating activities	**587**	260	212	160	121	81	19	69
Adjusted funds flow(1)	**587**	266	239	166	127	84	26	89
Per share, diluted	**1.87**	0.85	0.77	0.53	0.41	0.27	0.09	0.29
Capital expenditures	**88**	106	84	71	70	40	35	20
Working capital	**465**	150	199	127	8	55	131	173
Net debt - C$(1)	**2,150**	2,401	2,559	2,661	2,798	2,798	2,981	2,976
Net debt - US$(1)	**1,722**	1,897	2,007	2,145	2,226	2,194	2,237	2,186
Shareholders' equity	**4,178**	3,808	3,628	3,564	3,491	3,506	3,495	3,507
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**94.29**	77.19	70.56	66.07	57.84	42.66	40.93	27.85
Differential – WTI:WCS – Edmonton (US$/bbl)	**(14.53)**	(14.64)	(13.58)	(11.49)	(12.47)	(9.30)	(9.09)	(11.47)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(16.35)**	(16.40)	(15.13)	(13.11)	(14.22)	(10.56)	(10.48)	(13.44)
AWB – Edmonton (US$/bbl)	**77.94**	60.79	55.43	52.96	43.62	32.10	30.45	14.41
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(5.85)**	(6.40)	(5.57)	(3.92)	(2.52)	(2.83)	(3.20)	(7.29)
AWB – U.S. Gulf Coast (US$/bbl)	**88.44**	70.79	64.99	62.15	55.32	39.83	37.73	20.56
Enbridge Mainline heavy apportionment	**10 %**	21 %	53 %	46 %	48 %	22 %	9 %	13 %
C$ equivalent of 1US$ – average	**1.2661**	1.2600	1.2602	1.2280	1.2663	1.3031	1.3316	1.3860
Natural gas – AECO ($/mcf)	**5.16**	5.07	3.92	3.37	3.43	2.88	2.48	2.21
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**146,382**	141,280	127,546	129,474	128,236	136,623	93,479	100,980
Diluent usage – bbls/d	**(46,196)**	(42,386)	(35,295)	(39,494)	(40,938)	(40,892)	(25,910)	(30,583)
Bitumen sales – bbls/d	**100,186**	98,894	92,251	89,980	87,298	95,731	67,569	70,397
Bitumen production – bbls/d	**101,128**	100,698	91,506	91,803	90,842	91,030	71,516	75,687
Steam-oil ratio (SOR)	**2.43**	2.42	2.56	2.39	2.37	2.31	2.36	2.32
Blend sales(2)	**105.79**	82.43	74.54	69.27	61.28	45.75	45.44	20.96
Diluent expense	**(8.51)**	(11.37)	(9.63)	(9.18)	(8.94)	(7.11)	(5.76)	(10.78)
Bitumen realization(2)	**97.28**	71.06	64.91	60.09	52.34	38.64	39.68	10.18
Transportation & storage expense net of transportation revenue(2)	**(12.97)**	(11.39)	(10.03)	(10.91)	(11.41)	(14.11)	(18.55)	(11.77)
Curtailment	**—**	—	—	—	—	0.03	—	—
Royalties	**(5.24)**	(3.54)	(2.67)	(1.71)	(0.85)	(0.23)	(0.21)	(0.05)
Non-energy operating costs(3)	**(4.74)**	(4.56)	(4.46)	(3.84)	(4.05)	(4.70)	(3.96)	(4.09)
Energy operating costs(3)	**(6.80)**	(6.22)	(4.77)	(4.27)	(4.34)	(3.73)	(3.17)	(3.00)
Power revenue	**2.56**	2.58	2.06	2.57	3.14	1.45	1.08	0.95
Realized gain (loss) on commodity risk management	**0.12**	(10.06)	(7.73)	(10.63)	(8.80)	1.31	1.71	33.62
Cash operating netback(2)	**70.21**	37.87	37.31	31.30	26.03	18.66	16.58	25.84
Power sales price (C$/MWh)	**91.50**	95.22	82.17	88.40	93.27	46.34	39.03	28.34
Power sales (MW/h)	**121**	117	101	113	128	125	78	98
Average cost of diluent ($/bbl of diluent)	**124.23**	108.96	99.69	90.18	80.34	62.37	60.48	45.76
Average cost of diluent as a % of WTI	**104 %**	112 %	112 %	111 %	110 %	112 %	111 %	119 %
Depletion and depreciation rate per bbl of production	**13.58**	13.63	12.78	12.99	13.15	12.64	13.33	13.55
General and administrative expense per bbl of production	**1.61**	1.58	1.72	1.56	1.77	1.65	1.50	1.29
COMMON SHARES								
Shares outstanding, end of period (000)	**307,596**	306,865	306,773	306,716	303,137	302,681	302,657	302,645
Common share price ($) - close (end of period)	**17.07**	11.70	9.89	8.97	6.53	4.45	2.77	3.77

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

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

- significant variability in blend sales pricing primarily due to high volatility in the price of WTI which ranges from a quarterly average of US$27.85/bbl to US$94.29/bbl. The volatility in 2020 was driven by the impact of COVID-19 on supply and demand fundamentals. Since then we've seen a continual strengthening resulting from improved demand and declining inventories. Supply uncertainty further supported higher global crude oil prices as the February 2022 Russian invasion of Ukraine and subsequent sanctions against Russia created concern for significant oil supply disruption;
- the cost of diluent due to changes in Canadian and U.S. benchmark pricing, the timing of diluent inventory purchases and the impact of foreign exchange;
- changes in the value of the Canadian dollar relative to the U.S. dollar and its impact on blend sales prices, the cost of diluent, interest expense, and foreign exchange gains and losses associated with the Corporation's U.S. dollar denominated debt;
- timing of capital projects;
- cost reduction efforts;
- apportionment and the ability to reach USGC markets;
- fluctuations in natural gas and power pricing;
- gains and losses on risk management contracts;
- changes in depletion and depreciation expense as a result of changes in production rates, and future development costs;
- changes in the Corporation's share price and the implementation of financial equity price risk management contracts, and the resulting impact on stock-based compensation;
- planned turnaround and other maintenance activities affecting production; and
- voluntary curtailment efforts associated with uneconomic benchmark pricing environments.

23. ANNUAL SUMMARIES

	2021	2020	2019	2018(1)	2017(1)	2016(1)	2015(1)
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	283	(357)	(62)	(119)	166	(429)	(1,170)
Per share, diluted	0.91	(1.18)	(0.21)	(0.40)	0.57	(1.90)	(5.21)
Funds flow from operating activities	753	239	741	169	343	(69)	34
Adjusted funds flow(2)	799	275	724	175	371	(63)	49
Per share, diluted	2.57	0.90	2.41	0.58	1.28	(0.28)	0.22
Capital expenditures	331	149	198	622	508	140	314
Working capital	150	55	123	290	313	96	363
Net debt - C$(1)	2,401	2,798	2,917	3,422	4,205	4,897	4,782
Net debt - US$(1)	1,897	2,194	2,250	2,508	3,359	3,647	3,455
Shareholders' equity	3,808	3,506	3,853	3,886	3,964	3,287	3,678
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/bbl)	67.91	39.40	57.03	64.77	50.95	43.33	48.80
Differential – WTI:WCS – Edmonton (US$/bbl)	(13.04)	(12.60)	(12.76)	(26.31)	(11.98)	(13.84)	(13.52)
Differential – WTI:AWB – Edmonton (US$/bbl)	(14.71)	(14.32)	(14.95)	(29.99)	(14.09)	(16.40)	(16.69)
AWB – Edmonton (US$/bbl)	53.20	25.08	42.08	34.78	36.86	26.93	32.11
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	(4.60)	(4.77)	(1.77)	(6.68)	(7.61)	(11.53)	(8.53)
AWB - U.S. Gulf Coast (US$/bbl)	63.31	34.63	55.26	58.09	43.34	31.80	40.27
Enbridge Mainline heavy apportionment	42 %	24 %	43 %	41 %	20 %	12 %	31 %
C$ equivalent of 1US$ – average	1.2536	1.3413	1.3269	1.2962	1.2980	1.3256	1.2788
Natural gas – AECO ($/mcf)	3.95	2.43	1.92	1.62	2.29	2.25	2.71
OPERATIONAL **($/bbl unless specified)**							
Blend sales, net of purchased product – bbls/d	131,659	118,347	134,223	125,368	115,766	116,586	117,132
Diluent usage – bbls/d	(39,521)	(35,626)	(40,637)	(38,317)	(35,766)	(36,159)	(36,167)
Bitumen sales – bbls/d	92,138	82,721	93,586	87,051	80,000	80,427	80,965
Bitumen production – bbls/d	93,733	82,441	93,082	87,731	80,774	81,245	80,025
Steam-oil ratio (SOR)	2.43	2.32	2.22	2.19	2.31	2.29	2.47
Blend sales(3)	72.20	37.65	61.29	53.47	51.39	38.19	42.14
Diluent expense	(9.73)	(10.42)	(8.08)	(16.78)	(9.36)	(10.28)	(11.43)
Bitumen realization(3)	62.47	27.23	53.21	36.69	42.03	27.91	30.71
Transportation & storage expense net of transportation revenue(3)	(10.93)	(12.92)	(10.84)	(8.42)	(6.89)	(6.46)	(4.82)
Curtailment	—	0.06	(0.37)	—	—	—	—
Royalties	(2.25)	(0.31)	(1.30)	(1.20)	(0.77)	(0.29)	(0.70)
Non-energy operating costs(4)	(4.24)	(4.38)	(4.61)	(4.62)	(4.62)	(5.62)	(6.54)
Energy operating costs(4)	(4.94)	(3.29)	(2.38)	(1.98)	(2.98)	(3.01)	(3.84)
Power revenue	2.58	1.49	1.75	1.51	0.76	0.64	0.99
Realized gain (loss) on commodity risk management	(9.32)	11.34	(3.31)	(4.37)	(0.39)	0.08	—
Cash operating netback(3)	33.37	19.22	32.15	17.61	27.14	13.25	15.80
Power sales price (C$/MWh)	90.10	47.81	56.70	47.87	21.49	18.74	27.48
Power sales (MW/h)	115	108	121	114	118	115	121
Average cost of diluent ($/bbl of diluent)	94.88	61.86	79.89	91.60	72.32	61.06	67.72
Average cost of diluent as a % of WTI	111 %	117 %	106 %	109 %	109 %	106 %	109 %
Depletion and depreciation rate per bbl of production	13.15	13.60	20.90	14.12	16.13	16.81	16.00
General and administrative expense per bbl of production	1.65	1.62	1.99	2.58	2.94	3.24	4.06
COMMON SHARES							
Shares outstanding, end of period (000)	306,865	302,681	299,508	296,841	294,104	226,467	224,997
Common share price ($) - close (end of period)	11.70	4.45	7.39	7.71	5.14	9.23	8.02

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