FIRST QUARTER | 2021

REPORT TO SHAREHOLDERS FOR THE PERIOD ENDED MARCH 31, 2021

Report to Shareholders for the period ended March 31, 2021

(All financial figures are expressed in Canadian dollars ($ or C$) and all references to barrels are per barrel of bitumen, unless otherwise noted)

MEG Energy Corp. reported first quarter 2021 operational and financial results on May 3, 2021.

MEG continues to proactively respond to the safety challenges associated with the COVID-19 pandemic and remains committed to ensuring the health and safety of all of its personnel and the safe and reliable operation of the Christina Lake facility.

"MEG's first quarter was strong from both a financial and operational perspective" said Derek Evans, President and Chief Executive Officer. "We continue to benefit from both the strength in global oil market dynamics as well as the structural improvement in heavy oil differentials. Operationally, better than expected Christina Lake reservoir performance post the 75-day turnaround in 2020 has given us the confidence to tighten our production guidance and sets us up well for the balance of 2021."

Highlights include:

- Adjusted funds flow of $127 million ($0.41 per share), impacted by a realized commodity price risk management loss in the quarter of $69 million ($0.22 per share);

- Quarterly production volumes of 90,842 barrels per day (bbls/d) at a steam-oil ratio (SOR) of 2.37. Annual average production guidance has been revised to 88,000 – 90,000 bbls/d as production has continued to outpace expectations post the major turnaround in 2020;

- Net operating costs of $5.25 per barrel, including non-energy operating costs of $4.05 per barrel. Power revenue offset energy operating costs by 72%, resulting in a net impact of $1.20 per barrel;

- Successfully refinanced in the quarter US$600 million of existing indebtedness at a coupon of 5.875% due February 2029, which pushed out the earliest outstanding long term debt maturity to 2025; and

- Total capital investment of $70 million in the quarter was directed to sustaining and maintenance capital, resulting in $57 million of free cash flow in the quarter.

Blend Sales Pricing and North American Market Access

MEG realized an average AWB blend sales price of US$48.39 per barrel during the first quarter of 2021 compared to US$35.11 per barrel in the fourth quarter of 2020. The increase in average AWB blend sales price quarter over quarter was primarily a result of the average WTI price increasing by US$15.18 per barrel, partially offset by the average WTI:AWB differential at Edmonton widening by US$3.66 per barrel. MEG sold 38% of its sales volumes to the U.S. Gulf Coast ("USGC") in the first quarter of 2021 compared to 48% in the fourth quarter of 2020. The decrease in sales volume to the USGC in the first quarter of 2021 is a result of the Enbridge mainline apportionment increasing from 22% in the fourth quarter of 2020 to 48% in the first quarter of 2021.

Transportation and storage costs averaged US$6.13 per barrel of AWB blend sales in the first quarter of 2021 compared to US$7.59 per barrel of AWB blend sales in the fourth quarter of 2020. The decrease in transportation and storage costs is primarily due to less volumes shipped to the USGC and no FOB rail sales.

Operational Performance

Bitumen production averaged 90,842 bbls/d in the first quarter of 2021, consistent with average bitumen production of 91,030 bbls/d in the fourth quarter of 2020.

Non-energy operating costs averaged $4.05 per barrel of bitumen sales in the first quarter of 2021 compared to $4.70 per barrel in the fourth quarter of 2020. Energy operating costs, net of power revenue, averaged $1.20 per barrel in the first quarter of 2021 compared to $2.28 per barrel in the fourth quarter of 2020. MEG benefited from strong power prices on power sales from its cogeneration facilities whereby power revenue offset energy operating costs by 72% during the first quarter of 2021.

General & administrative expense ("G&A") was $14 million, or $1.77 per barrel of production, in the first quarter of 2021 compared to $14 million, or $1.65 per barrel of production, in the fourth quarter of 2020. The difference in per barrel G&A cost was due to lower production in the first quarter of 2021 compared to the fourth quarter of 2020.

Adjusted Funds Flow and Net Loss

MEG's bitumen realization averaged $52.34 per barrel in the first quarter of 2021 compared to $38.64 per barrel in the fourth quarter of 2020. The increase in average bitumen realization was due to the higher WTI price quarter over quarter. Offsetting the increase in bitumen realization during the first quarter of 2021, compared to the fourth quarter of 2020, was a realized commodity risk management loss of $8.80 per barrel in the first quarter of 2021 compared to a realized commodity risk management gain of $1.31 per barrel in the fourth quarter of 2020. This reflects stronger WTI settlement prices compared to WTI fixed price contracts in place.

The Corporation's cash operating netback averaged $26.03 per barrel in the first quarter of 2021 compared to $18.66 per barrel in the fourth quarter of 2020. The increased cash operating netback drove the increase in the Corporation's adjusted funds flow from $84 million in the fourth quarter of 2020 to $127 million in the first quarter of 2021.

The Corporation recognized a net loss of $17 million in the first quarter of 2021 compared to net earnings of $16 million in the fourth quarter of 2020. This change was primarily the result of a decreased unrealized gain on foreign exchange partially offset by the increased cash operating netback.

Capital Expenditures

MEG invested $70 million in the first quarter of 2021 compared to $40 million in the fourth quarter of 2020, which was primarily directed towards sustaining and maintenance activities.

Financial Liquidity

In February 2021, the Corporation successfully closed a private offering of US$600 million in aggregate principal amount of 5.875% senior unsecured notes due February 2029. The net proceeds of the offering plus cash-on-hand were used to fully redeem the remaining US$600 million of the 7.0% senior unsecured notes due March 2024. Post this refinancing, MEG maintains a 4-year runway until its next debt maturity represented by the remaining US$496 million of 6.50% second lien notes due January 2025.

MEG generated $57 million of free cash flow in the first quarter of 2021 and exited the quarter with $54 million of cash on hand. The Corporation's $800 million modified covenant-lite revolver, in place until July 2024, remains undrawn.

COVID-19 Global Pandemic

The Corporation continues to proactively respond to the safety challenges associated with COVID-19 and remains committed to ensuring the health and safety of all its personnel and business partners, and the safe and reliable operation of the Christina Lake facility. The screening procedures and protocols implemented by the Corporation's COVID-19 task force during the first quarter of 2020 continue to be enhanced to ensure continued safe and reliable operations. Flexibility and adaptability continue to be integral to the Corporation's response to the pandemic. The

Corporation continues to monitor the developing COVID-19 situation to determine what, if any, additional measures might need to be taken to ensure that the health and safety of its people remain a top priority.

Outlook

Based on better than expected production performance in the first quarter, MEG is revising its full year 2021 average production from 86,000 – 90,000 bbls/d to 88,000 – 90,000 bbls/d.

Due to increased apportionment on the Enbridge mainline, MEG is revising downward its expected sales into the U.S. Gulf coast via Flanagan South and Seaway Pipeline systems ("FSP") from approximately two-thirds of its full year 2021 AWB blend sales volumes to approximately 50%. As a result, MEG is revising downward its estimate of full year 2021 total transportation costs from US$7.75 to US$8.25 per barrel of AWB blend sales to US$6.75 to US$7.25 per barrel of AWB blend sales.

Summary of 2021 Guidance	2021 Revised Guidance	2021 Original Guidance
Bitumen production - annual average	88,000 - 90,000 bbls/d	86,000 - 90,000 bbls/d
Non-energy operating costs	$4.60 - $5.00 per bbl	$4.60 - $5.00 per bbl
G&A expense	$1.70 - $1.80 per bbl	$1.70 - $1.80 per bbl
Capital expenditures	$260 million	$260 million

2021 Commodity Price Risk Management

For the last nine months of 2021, MEG has entered into benchmark WTI fixed price hedges and enhanced WTI fixed price hedges with sold put options for approximately 37% of forecast bitumen production at an average price of US$46.20 per barrel. MEG has also hedged approximately 25% of its forecast Edmonton WTI:WCS differential exposure at an average differential of US$12.82 per barrel. MEG has also hedged approximately 40% of its expected 2021 condensate requirements at a landed-at-Edmonton price of 97% of WTI, approximately 35% of expected 2021 natural gas requirements at an average price of C$2.62 per GJ and fixed the sales price on approximately 25% of expected 2021 power available for sale at an average price of C$62.80 per MWh. The table below reflects MEG's 2021 hedge positions.

	Forecast Period		
	Q2 2021	Q3 2021	Q4 2021
WTI Hedges			
WTI Fixed Price Hedges			
Volume (bbls/d)	13,000	—	—
Weighted average fixed WTI price (US$/bbl)	$ 46.31	$ —	$ —
Enhanced WTI Fixed Price Hedges with Sold Put Options(1)			
Volume (bbls/d)	29,000	29,000	29,000
Weighted average fixed WTI price (US$/bbl) / Put option strike price (US$/bbl)	$ 46.18 / $ 38.79	$ 46.18 / $ 38.79	$ 46.18 / $ 38.79
WTI:WCS Differential Hedges			
Volume(2) (bbls/d)	43,000	10,000	—
Weighted average fixed WTI:WCS differential (US$/bbl)	$(13.24)	$(11.05)	$ —
Condensate Hedges			
Volume(3) (bbls/d)	18,211	14,028	14,028
Weighted average % of WTI landed in Edmonton (%)(4)	97 %	97 %	97 %
Natural Gas Hedges			
Volume(5) (GJ/d)	42,500	42,500	42,500
Weighted average fixed AECO price (C$/GJ)	$ 2.61	$ 2.61	$ 2.61
Power Hedges			
Quantity(6) (MW)	35	35	35
Weighted average fixed price (C$/MWh)	$ 62.75	$ 62.75	$ 62.75

(1) *If in any month the average WTI settlement price is US$38.79 per barrel (the sold put option) or better, MEG will receive US$46.18 per barrel (the fixed price swap) on each barrel hedged in that month. If in any month the average WTI settlement price is less than US$38.79 per barrel, MEG will receive the month average WTI settlement price in that month plus US$7.39 per barrel (the swap spread) on each barrel hedged in that month.*
(2) *Includes 15,000 bbls/d of physical forward blend sales in Q2 at fixed WTI:AWB differentials.*
(3) *Includes approximately 4,500 bbls/d of physical forward condensate purchases for Q2 to Q4 (average).*
(4) *The average % of WTI landed in Edmonton includes estimated net transportation costs to Edmonton.*
(5) *Includes 5,000 GJ/d of physical forward natural gas purchases for the Q2 to Q4 at a fixed AECO price.*
(6) *Represents physical forward power sales at a fixed power price.*

ADVISORY

Forward-Looking Information

This quarterly report contains forward-looking information and should be read in conjunction with the "Forward-Looking Information" contained within the Advisory section of this quarter's Management Discussion and Analysis and Press Release.

Non-GAAP Measures

Certain financial measures in this report to shareholders including free cash flow and cash operating netback are non-GAAP measures. These 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.

Free Cash Flow

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. Free cash flow is calculated as adjusted funds flow less capital expenditures.

	Three months ended March 31	
($millions)	**2021**	**2020**
Net cash provided by (used in) operating activities	**$ 12**	$ 99
Net change in non-cash operating working capital items	**109**	(30)
Funds flow from operations	**121**	69
Adjustments:		
Payments on onerous contracts	**6**	—
Contract cancellation	**—**	7
Adjusted funds flow	**$ 127**	$ 76
Capital expenditures	**(70)**	(54)
Free cash flow	**$ 57**	$ 22

Cash Operating Netback

Cash operating netback is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to fund future capital expenditures. The Corporation's cash operating netback is calculated by deducting the related cost of diluent, blend purchases, transportation and storage, third-party curtailment credits, operating expenses, royalties and realized commodity risk management gains or losses from blend sales and power revenue. The per barrel calculation of cash operating netback is based on bitumen sales volume.

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, 2021 was approved by the Corporation's Audit Committee on May 3, 2021. 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, 2021, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2020, the 2020 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.

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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 over 400 square miles of mineral leases. In the GLJ Petroleum Consultants Ltd. ("GLJ") report, which is dated effective December 31, 2020, GLJ estimated that the leases it had evaluated 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

The Corporation generated adjusted funds flow of $127 million in the first quarter of 2021 compared to $76 million in the first quarter of 2020, a 67% increase, reflecting stronger global crude oil prices and structural improvements in WTI:AWB differentials. The Corporation's blend sales price averaged $61.28 per barrel in the first quarter of 2021 compared to $36.46 per barrel in the first quarter of 2020, resulting from a 25% increase in the WTI benchmark price and a significant narrowing of the WTI:AWB differential at Edmonton and the U.S. Gulf Coast ("USGC"). This was partially offset by the Corporation's losses on commodity price risk management contracts which were in place to protect funding of the Corporation's 2021 capital program which is expected to be fully funded with internally generated cash flow.

Total capital spending of $70 million during the first quarter of 2021 compared to $54 million during the first quarter of 2020 was primarily focused on sustaining and maintenance capital. The increase in capital spending reflects the increased annual capital budget compared to 2020, as some prior year capital was shifted to 2021 in response to the economic environment associated with the COVID-19 global pandemic ("COVID-19").

On February 2, 2021, as previously announced, the Corporation refinanced US$600 million of its indebtedness to extend the Corporation's nearest outstanding long-term maturity to 2025 (from 2024).

The Corporation recognized a net loss of $17 million in the first quarter of 2021 mainly due to an unrealized loss on commodity risk management. This compares to a net loss of $284 million in the first quarter of 2020. Significant non-cash items impacted the decrease in the net loss including the $366 million exploration expense recognized in the first quarter of 2020 and an unrealized foreign exchange gain recognized in the first quarter of 2021 compared to an unrealized foreign exchange loss in the same period of 2020. These were partially offset by a commodity risk management loss in the first quarter of 2021 as a result of stronger forward commodity prices, compared to a significant commodity risk management gain in the same period of 2020.

COVID-19 Response

The Corporation continues to proactively respond to the safety challenges associated with COVID-19 and remains committed to ensuring the health and safety of all its personnel and business partners, and the safe and reliable operation of the Christina Lake facility. The screening procedures and protocols implemented by the Corporation's COVID-19 task force during the first quarter of 2020 continue to be enhanced to ensure continued safe and reliable operations. Flexibility and adaptability continue to be integral to the Corporation's response to the pandemic. The Corporation continues to monitor the developing COVID-19 situation to determine what, if any, additional measures might need to be taken to ensure that the health and safety of its people remain a top priority.

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:

	2021	2020				2019		
($millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Bitumen production - bbls/d	**90,842**	91,030	71,516	75,687	91,557	94,566	93,278	97,288
Steam-oil ratio	**2.37**	2.31	2.36	2.32	2.31	2.27	2.26	2.16
Bitumen sales - bbls/d	**87,298**	95,731	67,569	70,397	97,214	94,347	94,992	95,120
Bitumen realization - $/bbl	**52.34**	38.64	39.68	10.18	19.45	46.86	53.37	62.23
Net operating costs - $/bbl(1)	**5.25**	6.98	6.05	6.14	5.51	5.87	4.30	4.66
Non-energy operating costs - $/bbl	**4.05**	4.70	3.96	4.09	4.57	4.49	4.22	4.53
Cash operating netback - $/bbl(2)	**26.03**	18.66	16.58	25.84	16.83	28.33	32.44	37.88
General & administrative expense - $/bbl(3)	**1.77**	1.65	1.50	1.29	1.96	2.25	1.66	1.81
Adjusted funds flow(4)	**127**	84	26	89	76	155	191	227
Per share, diluted	**0.41**	0.27	0.09	0.29	0.25	0.51	0.63	0.75
Revenue	**914**	786	533	307	665	992	958	1,062
Net earnings (loss)	**(17)**	16	(9)	(80)	(284)	26	24	(64)
Per share, diluted	**(0.06)**	0.05	(0.03)	(0.26)	(0.95)	0.09	0.08	(0.21)
Capital expenditures	**70**	40	36	20	54	72	40	32
Cash and cash equivalents	**54**	114	49	120	62	206	154	399
Long-term debt - C$	**2,852**	2,912	3,030	3,096	3,212	3,123	3,257	3,582
Long-term debt - US$	**2,268**	2,283	2,274	2,274	2,275	2,409	2,459	2,737

(1) Net operating costs include energy and non-energy operating costs, reduced by power revenue.
(2) Cash operating netback is a non-GAAP measure and does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Refer to the "NON-GAAP MEASURES" section of this MD&A.
(3) General and administrative expense ("G&A") per barrel is based on bitumen production volumes.
(4) Refer to Note 17 of the interim consolidated financial statements for further details.

3. SUSTAINABILITY

The Corporation's approach to environmental, social and governance ("ESG") matters and sustainability reflects its understanding of the challenges presented by climate change and the energy transition and its commitment to taking appropriate actions. As the world moves towards a low-carbon future, the Corporation's business strategy recognizes the impact of reduced use of fossil fuels and addresses the risks arising out of climate change concerns. Although the timing and impact of the energy transition could be highly indeterminate, the Corporation is focused on enhancing its position as a sustainable low-cost producer and achieving net zero carbon emissions. For further details on the Corporation's approach, please refer to the 2020 annual MD&A and most recently filed Annual Information Form on www.sedar.com.

4. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended March 31	
	2021	**2020**
Bitumen production – bbls/d	**90,842**	91,557
Steam-oil ratio (SOR)	**2.37**	2.31

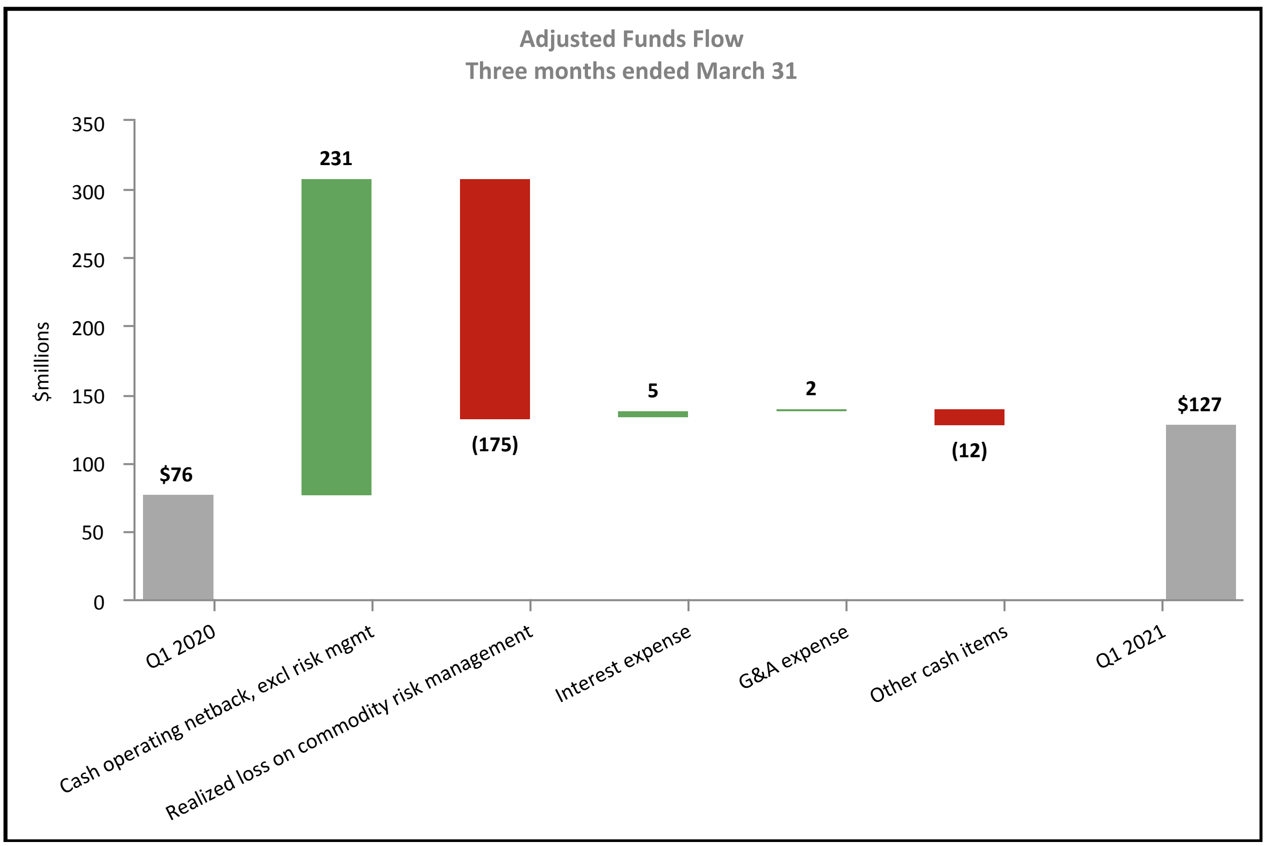
Bitumen Production

Bitumen production during the three months ended March 31, 2021 remained relatively consistent with the same period of 2020.

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, 2021, compared to the same period of 2020, due to the timing of new well pairs and wells being brought into steam circulation and production.

Adjusted Funds Flow



During the three months ended March 31, 2021, adjusted funds flow increased compared to the same period of 2020, driven by the Corporation's increased cash operating netback which was impacted by an increase in global crude oil prices partially offset by realized losses on commodity price risk management contracts. The commodity price risk management contracts were put in place to protect funding of the Corporation's 2021 capital program which is expected to be fully funded with internally generated cash flow.

The following table reconciles net cash provided by operating activities to adjusted funds flow:

	Three months ended March 31	
($millions)	**2021**	**2020**
Net cash provided by (used in) operating activities	**$ 12**	$ 99
Net change in non-cash operating working capital items	**109**	(30)
Funds flow from operations	**121**	69
Adjustments:		
Payments on onerous contracts	**6**	—
Contract cancellation	**—**	7
Adjusted funds flow	**$ 127**	$ 76

Net cash provided by operating activities is an IFRS measure in the Corporation's consolidated statement of cash flow. Adjusted funds flow is calculated as net cash provided by operating activities excluding the net change in non-cash operating working capital and 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 changes in non-cash working capital and other 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 for the years indicated below are based on bitumen sales volume.

	Three months ended March 31			
	2021		**2020**	
($millions, except as indicated)		**$/bbl**		**$/bbl**
Sales from production	**$ 695**		$ 469	
Sales from purchased product[1]	**198**		179	
Petroleum revenue	**893**		648	
Purchased product[1]	**(185)**		(176)	
Blend sales[2]	**$ 708**	**$ 61.28**	$ 472	$ 36.46
Cost of diluent	**(296)**	**(8.94)**	(300)	(17.01)
Bitumen realization	**412**	**52.34**	172	19.45
Transportation and storage[3]	**(90)**	**(11.41)**	(77)	(8.63)
Third-party curtailment credits[4]	**—**	**—**	2	0.18
Royalties	**(7)**	**(0.85)**	(6)	(0.63)
Net operating costs	**(41)**	**(5.25)**	(48)	(5.51)
Cash operating netback - excludes realized commodity risk management	**274**	**34.83**	43	4.86
Realized gain (loss) on commodity risk management	**(69)**	**(8.80)**	106	11.97
Cash operating netback[5]	**$ 205**	**$ 26.03**	$ 149	$ 16.83
Bitumen sales volumes - bbls/d		**87,298**		97,214

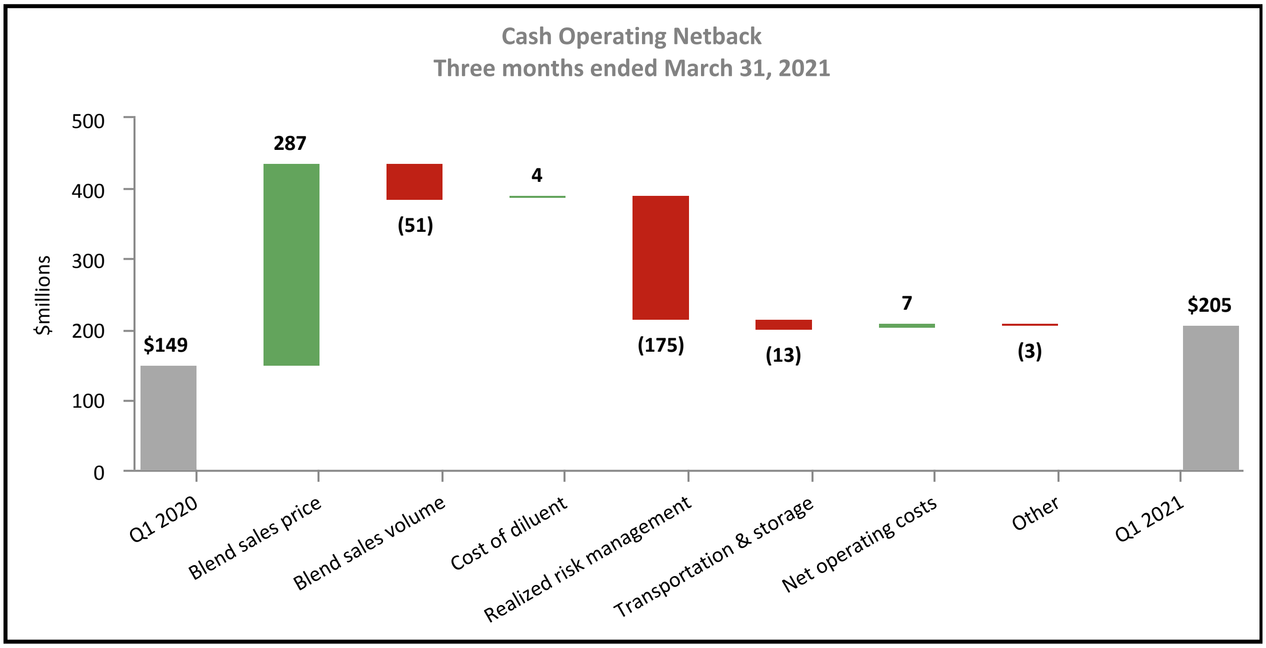
(1) Sales and purchases of oil products related to asset optimization activities.
(2) Blend sales per barrel are based on blend sales volumes.

(3) Transportation and storage includes costs associated with moving and storing blended barrels to optimize the timing of delivery, net of third-party recoveries on diluent transportation arrangements.

(4) During 2020, the Corporation had the ability to purchase or sell production curtailment credits to either increase its production, or sell excess production capacity, compared to its provincially-mandated curtailment level.

(5) A non-GAAP measure as defined in the "NON-GAAP MEASURES" section of this MD&A.

Blend sales includes net revenue related to asset optimization activities undertaken in the quarter. Marketing asset optimization is focused on the recovery of fixed costs related to transportation and storage contracts during periods of underutilization of such assets, with the goal to strengthen cash operating netback. 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 net of 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. 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 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 blended product volumes. Bitumen realization per barrel fluctuates primarily based on average benchmark prices and light:heavy oil differentials.

	Three months ended March 31			
	2021		2020	
($millions, except as indicated)		$/bbl		$/bbl
Sales from production	$ 695		$ 469	
Sales from purchased product[(1)]	198		179	
Petroleum revenue	$ 893		$ 648	
Purchased product[(1)]	(185)		(176)	
Blend sales[(2)]	$ 708	$ 61.28	$ 472	$ 36.46
Cost of diluent	(296)	(8.94)	(300)	(17.01)
Bitumen realization	$ 412	$ 52.34	$ 172	$ 19.45

(1) Sales and purchases of oil products related to asset optimization activities.
(2) Blend sales per barrel are based on blend sales volumes.

During the three months ended March 31, 2021, the blend sales price increased by $24.82 per barrel, or 68%, compared to the same period of 2020. The increase in blend sales price during the three months ended March 31, 2021 is due to a higher WTI price and a narrower WTI:AWB differential.

During the three months ended March 31, 2021, the cost of diluent decreased by $8.07 per barrel, or 47%, compared to the same period of 2020. The decrease reflects narrower WTI:AWB differentials which results in a higher recovery of the cost of diluent through blend sales.

The cost per barrel of diluent recognized during the three months ended March 31, 2021 was $80.34 compared to $73.09 for the same period of 2020. 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. 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

The Corporation's marketing strategy focuses on maximizing the realized AWB sales price after transportation and storage costs by utilizing its network of pipeline and storage facilities to optimize market access.

	Three months ended March 31			
	2021		2020	
($millions, except as indicated)		$/bbl		$/bbl
Transportation and storage	$ (90)	$ (11.41)	$ (77)	$ (8.63)
Bitumen sales volumes - bbls/d		87,298		97,214

During the three months ended March 31, 2021, total transportation and storage costs increased by 17% compared to the same period of 2020. The increase is primarily the result of additional transportation costs associated with the increased capacity on Flanagan South and Seaway Pipeline ("FSP") systems beginning in July 2020, partially offset by the absence of rail activity during the three months ended March 31, 2021.

Transportation and storage costs on a per barrel basis increased during the three months ended March 31, 2021, compared to the same period of 2020, as increased fixed costs were allocated over lower sales volumes.

The Corporation partially mitigated the cost of unutilized transportation and storage assets through the purchase and sale of non-proprietary product. These asset optimization activities added $13 million, or $1.07 per barrel to blend sales, during the three months ended March 31, 2021 compared to $3 million, or $0.24 per barrel to blend sales, during the same period of 2020. The Corporation does not engage in speculative trading. The purchase and sale of third-party products 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. To the extent that marketing asset capacity is underutilized, the Corporation has and will continue to look to mitigate these costs through short and medium-term third-party contracts.

Royalties

The Corporation's royalty expense is calculated based on price-sensitive royalty rates set by the Government of Alberta. The royalty rate applicable to the Corporation's Christina Lake operation, which is currently in pre-payout, starts at 1% of bitumen sales and increases for every dollar that 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 applicable royalty rate is then applied to revenue for royalty purposes.

	Three months ended March 31			
	2021		2020	
($millions, except as indicated)		$/bbl		$/bbl
Royalties	**$ (7)**	**$ (0.85)**	$ (6)	$ (0.63)

The increase in royalties for the three months ended March 31, 2021, compared to the same period of 2020, is the result of the increase in the WTI benchmark price.

Net Operating Costs

Net operating costs 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			
	2021		2020	
($millions, except as indicated)		$/bbl		$/bbl
Non-energy operating costs	**$ (32)**	**$ (4.05)**	$ (40)	$ (4.57)
Energy operating costs	**(34)**	**(4.34)**	(28)	(3.15)
Power revenue	**25**	**3.14**	20	2.21
Net operating costs	**$ (41)**	**$ (5.25)**	$ (48)	$ (5.51)
Average natural gas purchase price (C$/mcf)		**$ 3.62**		$ 2.63
Average realized power sales price (C$/Mwh)		**$ 93.27**		$ 69.39

Non-energy operating costs decreased for the three months ended March 31, 2021, compared to the same period of 2020. Throughout the past year, the Corporation took measures to reduce costs through reductions in staffing levels. Also contributing to the decrease were various government led initiatives to assist the industry through unprecedented market volatility associated with COVID-19, which resulted in the collapse of oil prices in 2020.

Power revenue offset energy operating costs by 74% during the three months ended March 31, 2021 compared to 71% during the same period of 2020. Energy operating costs increased predominantly due to the AECO natural gas market strengthening. This was partially offset by the Alberta power market strengthening.

Realized Gain or Loss on Commodity Risk Management

The Corporation enters into financial commodity risk management contracts to increase the predictability of the Corporation's cash flow by managing commodity price volatility.

	Three months ended March 31			
	2021		2020	
($millions, except as indicated)		$/bbl		$/bbl
Realized gain (loss) on commodity risk management	**$ (69)**	**$ (8.80)**	$ 106	$ 11.97

Realized losses on commodity risk management contracts were recognized during the three months ended March 31, 2021 primarily due to the increase in the WTI price in the first quarter of 2021 compared to the WTI fixed price contracts in place. Conversely, realized gains were recognized during the three months ended March 31, 2020 due to the significant weakening in the WTI price compared to the WTI fixed price contracts in place at that time. Refer to the commodity risk management discussion within the “OTHER OPERATING RESULTS” section of this MD&A for further details.

Marketing Activity

The following tables summarize the Corporation's blend sales, net of transportation and storage at Edmonton by sales market for the periods noted to assist in understanding the Corporation's marketing portfolio. All per barrel figures presented in this section of the MD&A are based on US$ per barrel of blend sales volumes unless otherwise indicated:

Blend sales distribution by sales market	Three months ended March 31, 2021		
	Edmonton (US$/bbl)	USGC (US$/bbl)	TOTAL (US$/bbl)
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Pipeline[3]	
WTI - benchmark	$ 57.84	$ 57.84	$ 57.84
Differential - WTI:AWB at sales point	(14.78)	(2.92)	(10.30)
Asset optimization	—	2.24	0.85
Blend sales price	43.06	57.16	48.39
Transportation and storage[1]	(2.01)	(12.86)	(6.13)
Transportation and storage from Christina Lake to Edmonton[2]	2.01	2.01	2.01
Blend sales price, net of transportation & storage at Edmonton	$ 43.06	$ 46.31	$ 44.27
Total blend sales - bbls/d	79,708	48,528	128,236
% of total sales	62 %	38 %	100 %

USGC sales price premium	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 43.06	$ 57.16	$ 14.10
Transportation and storage[1]	(2.01)	(12.86)	(10.85)
Transportation and storage from Christina Lake to Edmonton[2]	2.01	2.01	—
Blend sales price, net of transportation & storage at Edmonton	$ 43.06	$ 46.31	$ 3.25

Blend sales distribution by sales market	Three months ended March 31, 2020				
	Edmonton (US$/bbl)		USGC (US$/bbl)		TOTAL (US$/bbl)
(US$ per barrel of blend sales, unless otherwise indicated)	Pipeline	Rail	Pipeline[3]	Rail	
WTI - benchmark	$ 46.17	$ 46.17	$ 46.17	$ 46.17	$ 46.17
Differential - WTI:AWB at sales point	(23.99)	(21.56)	(5.27)	3.49	(19.23)
Asset optimization	—	—	0.86	—	0.18
Blend sales price	22.18	24.61	41.76	49.66	27.12
Transportation and storage[1]	(1.82)	(3.45)	(11.01)	(24.73)	(4.39)
Transportation and storage from Christina Lake to Edmonton[2]	1.82	1.82	1.82	1.82	1.82
Blend sales price, net of transportation & storage at Edmonton	$ 22.18	$ 22.98	$ 32.57	$ 26.75	$ 24.55
Total blend sales - bbls/d	82,957	27,867	29,271	2,285	142,380
% of total sales	58 %	19 %	21 %	2 %	100 %

USGC sales price premium	Edmonton (US$/bbl)	USGC (US$/bbl)	USGC premium (US$/bbl)
Average blend sales price by location	$ 22.79	$ 42.33	$ 19.54
Transportation and storage[1]	(2.23)	(12.00)	(9.77)
Transportation and storage from Christina Lake to Edmonton[2]	1.82	1.82	—
Blend sales price, net of transportation & storage at Edmonton	$ 22.38	$ 32.15	$ 9.77

(1) *Defined as transportation and storage expenses less transportation revenue, per barrel of blend sales volumes. For reference, total transportation and storage costs per barrel, based on bitumen sales volumes, were C$11.41 per barrel for the three months ended March 31, 2021 compared to C$8.63 per barrel for the three months ended March 31, 2020.*

(2) *Includes all transportation and storage costs associated with moving barrels of blend from Christina Lake to Edmonton sales point.*

(3) *Sales from marketing asset optimization activities are recognized in the blend sales price and not as a recovery of transportation and storage costs for consistency with the financial statements. During the three months ended March 31, 2021 these activities contributed US$2.24 per barrel to the blend sales price at the USGC (pipeline) compared to US$0.86 during the same period of 2020. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC (pipeline) during the three months ended March 31, 2021 would be US$10.62 per barrel compared to US$12.86 per barrel. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC (pipeline) during the three months ended March 31, 2020 would be US$10.15 per barrel compared to US$11.01 per barrel.*

(4) *Results are translated at the average foreign exchange rate of 1.2663 for the three months ended March 31, 2021 and 1.3445 for the three months ended March 31, 2020.*

Excluding transportation and storage costs upstream of the Edmonton market, the Corporation's net AWB blend sales price averaged US$44.27 per barrel during the three months ended March 31, 2021 compared to the posted AWB benchmark price at Edmonton of US$43.62 per barrel. Notwithstanding high levels of apportionment, this is largely the result of increased sales exposure to the USGC market with the Corporation benefiting from the increased FSP transportation commitment.

Effective July 1, 2020, the Corporation's contracted transportation capacity on FSP increased from 50,000 bbls/d to 100,000 bbls/d. The Corporation's access to the USGC, where sales pricing is not subject to the same light:heavy oil differential as at the Edmonton market, translated into a premium earned on blend sales at the USGC over the Edmonton market of US$3.25 per barrel for the three months ended March 31, 2021. This compares to a premium of US$9.77 per barrel at the USGC compared to the Edmonton market during the same period of 2020. The lower premium, compared to the same period of 2020, is primarily the result of narrower realized differentials at Edmonton during the three months ended March 31, 2021, as well as increased transportation costs per barrel resulting from the increased FSP transportation commitment.

Revenue

Revenue 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	
($millions)	**2021**	**2020**
Sales from:		
Production	**$ 695**	$ 469
Purchased product[1]	**198**	179
Petroleum revenue	**$ 893**	$ 648
Royalties	**(7)**	(6)
Petroleum revenue, net of royalties	**$ 886**	$ 642
Power revenue	**$ 25**	$ 20
Transportation revenue	**3**	3
Other revenue	**$ 28**	$ 23
Total revenues	**$ 914**	$ 665

(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, 2021, total revenues increased 37% from the same period of 2020 primarily as a result of the increase to the average blend sales price driven by the increase in WTI prices and the narrowing of the WTI:AWB differential, partially offset by an 11% decrease in blend sales volumes.

Net Loss

	Three months ended March 31	
($millions, except per share amounts)	**2021**	**2020**
Net loss	**$ (17)**	$ (284)
Per share, diluted	**$ (0.06)**	$ (0.95)

The Corporation recognized a net loss of $17 million during the three months ended March 31, 2021 mainly due to an unrealized loss on commodity risk management. This compares to a net loss of $284 million during the same period of 2020. Significant non-cash items impacted the decrease in the net loss including the $366 million exploration expense recognized during the three months ended March 31, 2020 and an unrealized foreign exchange gain recognized during the three months ended March 31, 2021 compared to an unrealized foreign exchange loss in the same period of 2020. These were partially offset by a commodity risk management loss during the three months ended March 31, 2021 as a result of stronger forward commodity prices compared to a significant commodity risk management gain in the same period of 2020.

Capital Expenditures

	Three months ended March 31	
($millions)	**2021**	**2020**
Sustaining and maintenance	**$ 65**	$ 40
Phase 2B brownfield expansion	**4**	13
eMVAPEX	**—**	3
Field infrastructure, corporate and other	**1**	—
	$ 70	$ 56
eMVAPEX goverment grant	**—**	(2)
	$ 70	$ 54

The increase in capital spending for the three months ended March 31, 2021, compared to the same period of 2020, reflects the Corporation's decision to reduce capital spending in 2020 due to the unprecedented negative oil price environment experienced in the first half of 2020 when reductions in the Corporation's planned capital program were announced. Approximately 80% of the reductions were deferred to the Corporation's 2021 capital budget. Capital expenditures during the three months ended March 31, 2021 primarily consisted of sustaining and maintenance activities. The Corporation's eMVAPEX pilot has achieved most of its preliminary goals and is in the process of recovering previously injected solvent. The Corporation is investigating opportunities to utilize the process.

5. OUTLOOK

On December 7, 2020 the Corporation released its original 2021 capital and operating budget. On May 3, 2021, the Corporation revised its 2021 annual guidance. Based on better than expected production performance in the first quarter of 2021, the Corporation revised its full year 2021 average production from 86,000 – 90,000 bbls/d to 88,000 – 90,000 bbls/d.

Summary of 2021 Guidance	**2021 Revised Guidance**	**2021 Original Guidance**
Bitumen production - annual average	88,000 - 90,000 bbls/d	86,000 - 90,000 bbls/d
Non-energy operating costs	$4.60 - $5.00 per bbl	$4.60 - $5.00 per bbl
G&A expense	$1.70 - $1.80 per bbl	$1.70 - $1.80 per bbl
Capital expenditures	$260 million	$260 million

Due to increased apportionment on the Enbridge mainline, MEG is revising downward its expected sales into the USGC via FSP from approximately two-thirds of its full year 2021 AWB blend sales volumes to approximately 50%. As a result, MEG is revising downward its estimate of full year 2021 total transportation costs from US$7.75 to US$8.25 per barrel of AWB blend sales to US$6.75 to US$7.25 per barrel of AWB blend sales.

6. 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:

	2021	2020				2019		
	Q1	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Average Benchmark Commodity Prices								
Crude oil prices								
Brent (US$/bbl)	**61.06**	**45.25**	43.39	33.30	50.95	62.50	61.97	68.32
WTI (US$/bbl)	**57.84**	**42.66**	40.93	27.85	46.17	56.96	56.45	59.82
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.47)**	**(9.30)**	(9.09)	(11.47)	(20.53)	(15.83)	(12.24)	(10.67)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(14.22)**	**(10.56)**	(10.48)	(13.44)	(22.78)	(18.44)	(14.52)	(12.32)
AWB – Edmonton (US$/bbl)	**43.62**	**32.10**	30.45	14.41	23.39	38.52	41.93	47.50
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(2.52)**	**(2.83)**	(3.20)	(7.29)	(5.74)	(5.25)	(2.50)	1.64
AWB – U.S. Gulf Coast (US$/bbl)	**55.32**	**39.83**	37.73	20.56	40.43	51.71	53.95	61.46
Condensate prices								
Condensate at Edmonton (C$/bbl)	**73.51**	**55.39**	50.03	30.72	61.76	70.01	68.73	74.76
Condensate at Edmonton as % of WTI	**100.4%**	**99.6%**	91.8%	79.6%	99.5%	93.1%	92.2%	93.4%
Condensate at Mont Belvieu, Texas (US$/bbl)	**56.00**	**38.52**	33.52	17.43	39.27	50.08	44.34	50.22
Condensate at Mont Belvieu, Texas as % of WTI	**96.8%**	**90.3%**	81.9%	62.6%	85.1%	87.9%	78.5%	84.0%
Natural gas prices								
AECO (C$/mcf)	**3.43**	**2.88**	2.48	2.21	2.26	2.70	0.95	1.12
Electric power prices								
Alberta power pool (C$/MWh)	**97.25**	**46.05**	43.75	29.94	66.38	47.07	46.95	56.37
Foreign exchange rates								
C$ equivalent of 1 US$ – average	**1.2663**	**1.3031**	1.3316	1.3860	1.3445	1.3201	1.3207	1.3376
C$ equivalent of 1 US$ – period end	**1.2572**	**1.2755**	1.3324	1.3616	1.4120	1.2965	1.3244	1.3091

Beginning in early March 2020, market conditions precipitated by COVID-19, and subsequent measures intended to limit the outbreak globally, contributed to an unprecedented impact on global crude oil demand. At the same time, overall global crude oil supply increased as efforts between the Organization of Petroleum Exporting Countries ("OPEC") and non-OPEC members to manage global crude oil production levels broke down and each party increased their daily crude production. With reduced crude oil demand and excess supply, the price of crude oil and other petroleum products deteriorated significantly during the first half of 2020. However, during the second quarter of 2020, the agreement between OPEC and a group of 10 non-OPEC members (collectively, "OPEC+") to cut crude oil output, and several other countries announcing similar production cuts, decreased the global crude oil supply. At the same time, governments began to ease off on some of the measures taken to contain COVID-19 increasing demand for crude oil, which helped increase global crude oil prices during the second half of 2020 and thus far in 2021. Price volatility remains largely due to market sensitivity to COVID-19 related news including vaccine breakthroughs and rollouts, and the resurgence of COVID-19 cases and developing variants of concern as well as OPEC+ related news.

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.

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. 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 bbls/d at the USGC reference benchmark pricing at Mont Belvieu, Texas. Condensate pricing was impacted by market conditions precipitated by COVID-19 when condensate pricing fell sharply in the second quarter of 2020 which was in line with reduced thermal oil production and lower demand for diluent. During the second half of 2020, condensate pricing steadily increased as pricing came back in line with WTI. Condensate pricing has subsequently strengthened beyond levels seen prior to COVID-19 as supply has not responded as quickly as demand in both the Edmonton area and USGC. Refer to bitumen realization within the "CASH OPERATING NETBACK" section of this MD&A for further details.

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. The AECO natural gas price increased during the three months ended March 31, 2021 compared to the same period of 2020 due to market uncertainty surrounding possible gas supply constraints in 2021, coupled with extreme weather conditions in February.

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 increased during the three months ended March 31, 2021 compared to the same period of 2020 primarily as a result of extreme winter conditions in February of 2021.

7. OTHER OPERATING RESULTS

General and Administrative

	Three months ended March 31	
($millions, except as indicated)	**2021**	**2020**
General and administrative	**$ 14**	$ 16
General and administrative expense per barrel of production	**$ 1.77**	$ 1.96

Throughout 2020, the Corporation drove efficiencies into its cost structure through various efforts including reductions in staffing levels as well as temporary salary rollbacks, vendor concessions and various government led initiatives to assist the industry through unprecedented market volatility. As a result of these efficiencies, G&A expense decreased 13% for the three months ended March 31, 2021 compared to the same period of 2020.

Depletion and Depreciation

	Three months ended March 31	
($millions, except as indicated)	**2021**	**2020**
Depletion and depreciation expense	**$ 108**	$ 124
Depletion and depreciation expense per barrel of production	**$ 13.15**	$ 14.83

Depletion and depreciation expense was $13.15 per barrel for the three months ended March 31, 2021 compared to $14.83 per barrel for the three months ended March 31, 2020. Depletion and depreciation expense decreased primarily due to an accelerated depreciation expense of $13 million, or $1.57 per barrel, incurred during the three months ended March 31, 2020 given the uncertainty of future benefits associated with certain non-core assets.

Exploration Expense

	Three months ended March 31	
($millions)	**2021**	**2020**
Exploration expense	**$ —**	$ 366

Exploration expense is recognized when facts and circumstances suggest that the carrying amount exceeds the recoverable amount and the Corporation decides to discontinue exploration and evaluation activities which are pending the determination of proved or probable reserves. During the three months ended March 31, 2021 there was no exploration expense recognized. During the three months ended March 31, 2020 the Corporation discontinued exploration and evaluation activities in certain non-core growth properties as it narrowed the development focus to core assets at Christina Lake. The associated land lease and evaluation costs totaling $366 million were charged to exploration expense.

Commodity Risk Management Gain (Loss)

The Corporation enters into financial commodity risk management contracts to increase the predictability of the Corporation's cash flow by managing commodity price volatility. The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes. All 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 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.

	Three months ended March 31	
($millions)	**2021**	**2020**
Realized:		
Crude oil contracts[1]	**$ (81)**	$ 109
Condensate contracts[2]	**11**	(3)
Natural gas contracts[3]	**1**	—
Realized commodity risk management gain (loss)	**$ (69)**	$ 106
Unrealized:		
Crude oil contracts[1]	**$ (86)**	$ 439
Condensate contracts[2]	**(6)**	(11)
Natural gas contracts[3]	**4**	—
Unrealized commodity risk management gain (loss)	**$ (88)**	$ 428
Commodity risk management gain (loss)	**$ (157)**	$ 534

(1) Includes WTI fixed price contracts, WTI enhanced fixed price with sold put options contracts 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, 2021, the Corporation recognized a $157 million net loss from commodity risk management primarily due to losses on settlement of WTI fixed price contracts, as actual WTI prices were stronger than contracted prices during the period. This compares with the $534 million net gain from commodity risk management for the three months ended March 31, 2020, when WTI prices were weaker than contracted prices due to a significant decline in early March 2020 driven by the demand shock on global markets largely due to the impact driven by COVID-19 developments.

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$/bbl)	**2021**	**2020**
WTI fixed price contracts:		
Average fixed price	**$ 46.96**	$ 58.67
Average settlement price	**57.82**	46.17
Gain (loss) on WTI fixed price contracts	**$ (10.86)**	$ 12.50
WTI:WCS fixed differential contracts:		
Average fixed differential	**$ (13.46)**	$ (22.18)
Average settlement differential	**(11.46)**	(20.53)
Gain (loss) on WTI:WCS fixed differential contracts	**$ (2.00)**	$ (1.65)
Condensate purchase contracts:		
Average fixed differential[(1)]	**$ (10.37)**	$ (5.33)
Average settlement differential	**(1.84)**	(6.90)
Gain (loss) on condensate purchase contracts	**$ 8.53**	$ (1.57)
(C$/GJ)		
Natural gas purchase contracts:		
Average fixed price	**$ 2.61**	$ —
Average settlement price	**2.95**	—
Gain (loss) on natural gas purchase contracts	**$ 0.34**	$ —

(1) 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	
($millions)	**2021**	**2020**
Cash-settled expense (recovery)	**$ 19**	$ (18)
Equity-settled expense	**2**	5
Equity price risk management (gain) loss[(1)]	**(19)**	$ —
Stock-based compensation expense (recovery)	**$ 2**	$ (13)

(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 Risk Management section 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 $6.53 per share as at March 31, 2021, from its value of $4.45 per share as at December 31, 2020. Conversely, the cash-settled recovery as at March 31, 2020 was primarily due to the decrease in the Corporation's share price to $1.67 per share as at March 31, 2020 from its value of $7.39 per share as at December 31, 2019.

Equity-settled stock-based compensation expense decreased for the three months ended March 31, 2021, compared to the same period of 2020, primarily due to a decrease in the value of awards granted.

The equity price risk management (gain) loss 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, 2021, an equity price risk management gain of $19 million was recognized on the increase in share price since inception in March 2020.

Foreign Exchange Gain (Loss), Net

	Three months ended March 31	
($millions)	**2021**	**2020**
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ 48**	$ (278)
US$ denominated cash and cash equivalents	**(5)**	11
Unrealized net gain (loss) on foreign exchange	**43**	(267)
Realized gain (loss) on foreign exchange	**—**	(3)
Foreign exchange gain (loss), net	**$ 43**	$ (270)

C$ equivalent of 1 US$		
Beginning of period	**1.2755**	1.2965
End of period	**1.2572**	1.4120

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, 2021, the Canadian dollar strengthened relative to the U.S. dollar by 1%, resulting in an unrealized foreign exchange gain of $43 million. For the three months ended March 31, 2020, the Canadian dollar weakened by 9%, resulting in an unrealized foreign exchange loss of $267 million.

Net Finance Expense

	Three months ended March 31	
($millions)	**2021**	**2020**
Interest expense on long-term debt	**$ 58**	$ 64
Interest expense on lease liabilities	**6**	6
Interest income	**—**	(2)
Net interest expense	**64**	68
Accretion on provisions	**2**	2
Net finance expense	**$ 66**	$ 70

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

Income Tax

	Three months ended March 31	
($millions)	**2021**	**2020**
Income tax expense (recovery)	**$ (19)**	$ (2)
Effective tax rate	**52 %**	1 %

As at March 31, 2021, the Corporation had approximately $7.5 billion of available Canadian tax pools and recognized a deferred income tax asset of $400 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

The effective tax rate of 52% for the three months ended March 31, 2021 is higher than the Canadian statutory rate of 23% primarily due to the tax effect of realized and unrealized foreign exchange losses on the Corporation's debt which is denominated in US dollars.

8. LIQUIDITY AND CAPITAL RESOURCES

($millions)	March 31, 2021	December 31, 2020
Second Lien:		
6.5% senior secured second lien notes (March 31, 2021 - US$496 million; December 31, 2020 - US$496 million; due 2025)	**$ 624**	$ 633
Unsecured:		
7.125% senior unsecured notes (March 31, 2021 - US$1.2 billion; December 31, 2020 - US$1.2 billion; due 2027)	**1,509**	1,531
5.875% senior unsecured notes (March 31, 2021 - US$600 million; December 31, 2020 - US$nil; due 2029)	**754**	—
7.0% senior unsecured notes (March 31, 2021 - US$nil; December 31, 2020 - US$600 million; due 2024)	**—**	765
Less:		
Debt redemption premium	**—**	9
Unamortized deferred debt discount and debt issue costs	**(35)**	(26)
Long-term debt	**2,852**	2,912
Cash and cash equivalents	**(54)**	(114)
Net debt(1)	**$ 2,798**	$ 2,798

(1) *Net debt is reconciled to long-term debt in accordance with IFRS in Note 17 of the interim consolidated financial statements.*

On February 2, 2021, the Corporation successfully closed a private offering of US$600 million in aggregate principal amount of 5.875% senior unsecured notes due February 2029. The net proceeds of the offering, together with cash-on-hand, were used to fully redeem US$600 million in aggregate principal amount of its 7.0% senior unsecured notes due March 2024 at a redemption price of 101.167% and to pay fees and expenses related to the offering.

The Corporation's cash and cash equivalents balance was $54 million as at March 31, 2021 compared to $114 million as at December 31, 2020. 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 driven by COVID-19 developments continues to be supported by the Corporation's financial framework, including a commodity risk management program securing cash flow through 2021, and credit risk management policies minimizing credit exposure on sales to primarily investment grade customers in the energy industry. The Corporation's earliest maturing long-term debt is nearly four years out, represented by US$496 million of senior secured second lien notes due January 2025. None of the Corporation’s outstanding long-term debt contain financial maintenance covenants. 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, 2021, the Corporation had $785 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 that remains outstanding. 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	
($millions)	**2021**	**2020**
Net cash provided by (used in):		
Operating activities	**$ 12**	$ 99
Investing activities	**(49)**	(59)
Financing activities	**(17)**	(196)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(6)**	12
Change in cash and cash equivalents	**$ (60)**	$ (144)

Cash Flow – Operating Activities

Net cash provided by operating activities for the three months ended March 31, 2021 decreased compared to the same period of 2020, primarily due to a change in working capital requirements. Before non-cash working capital, funds flow from operating activities increased mainly due to higher benchmark crude oil prices.

Cash Flow – Investing Activities

Net cash used in investing activities decreased during the three months ended March 31, 2021 compared to the same period of 2020 which reflects the Corporation's increased change in non-cash working capital partially offset by increased capital spending.

Cash Flow – Financing Activities

Net cash used in financing activities for the three months ended March 31, 2021 decreased compared to the same period of 2020, primarily due to the higher debt redemption and refinancing costs during the three months ended March 31, 2020.

9. 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 crude oil sales, condensate purchases and natural gas purchases outstanding as at March 31, 2021:

As at March 31, 2021			
Crude Oil Sales Contracts[1]	**Volumes (bbls/d)**[2]	**Term**	**Average Price (US$/bbl)**[2]
WTI Fixed Price	13,000	Apr 1, 2021 - Jun 30, 2021	$46.31
WTI:WCS Fixed Differential	28,000	Apr 1, 2021 - Jun 30, 2021	$(12.26)
WTI:WCS Fixed Differential	10,000	Jul 1, 2021 - Sep 30, 2021	$(11.05)
Enhanced Fixed Price with Sold Put Option			
WTI Fixed Price/Sold Put Option Strike Price	29,000	Apr 1, 2021 - Dec 31, 2021	$46.18 / $38.79
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	10,950	Apr 1, 2021 - Dec 31, 2021	$(10.37)
WTI:Mont Belvieu Fixed Differential	200	Jan 1, 2022 - Dec 31, 2022	$(11.30)
Natural Gas Purchase Contracts	**Volumes (GJ/d)**[2]	**Term**	**Average Price (C$/GJ)**[2]
AECO Fixed Price	37,500	Apr 1, 2021 - Dec 31, 2021	$2.60

(1) *Incremental to these crude oil sales contracts, the Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months.*

(2) *The volumes and prices in the above table represent averages for various contracts with differing terms and prices. The* average *prices for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.*

The Corporation did not enter into financial commodity risk management contracts between March 31, 2021 and May 3, 2021.

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 as at March 31, 2021:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	**$ (57)**	**$ 55**
Crude oil differential price	± US$5.00 per bbl applied to WTI:WCS differential contracts	**$ 22**	**$ (22)**
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)**

The Corporation had the following physical commodity risk management contracts relating to crude oil sales, condensate purchases, natural gas purchases and power sales outstanding as at May 3, 2021:

Crude Oil Sales Contracts	Volumes (bbls/d)(1)	Term	Average Price (US$/bbl)(1)
WTI:AWB Fixed Differential	15,000	Apr 1, 2021 - Jun 30, 2021	$(17.65)
Condensate Purchase Contracts			
WTI:Condensate Fixed Differential	7,261	Apr 1, 2021 - June 30, 2021	$(0.94)
WTI:Condensate Fixed Differential	3,078	Jul 1, 2021 - Dec 31, 2021	$(1.80)
Natural Gas Purchase Contracts	**Volumes (GJ/d)(1)**	**Term**	**Average Price (C$/GJ)(1)**
AECO Fixed Price	5,000	Apr 1, 2021 - Dec 31, 2021	$2.70
Power Sales Contracts	**Quantity (MW)(1)**	**Term**	**Average Price (C$/MWh)(1)**
Fixed Price	35	Apr 1, 2021 - Dec 31, 2021	$62.75

(1) The volumes and prices in the above table represent averages for various contracts with differing terms and prices. The average price for the portfolio may not have the same payment profile as the individual contracts and is provided for indicative purposes.

Equity Price Risk Management

The Corporation enters 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 and funds flow from operating activities are impacted when outstanding cash-settled RSUs and PSUs, issued under the Corporation's stock-based compensation plans, are revalued each period based on the Corporation's share price. 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 to manage its exposure on cash-settled RSUs and PSUs vesting between 2021 and 2023.

	Three months ended March 31	
($millions)	**2021**	**2020**
Unrealized equity price risk management (gain) loss	**$ (11)**	$ —
Realized equity price risk management (gain) loss	**(8)**	—
Equity price risk management (gain) loss	**$ (19)**	$ —

10. SHARES OUTSTANDING

As at March 31, 2021, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	**Units**
Common shares	**303.1**
Convertible securities	
Stock options(1)	**4.2**
Equity-settled RSUs and PSUs	**6.6**

(1) 3.7 million stock options were exercisable as at March 31, 2021.

As at April 30, 2021, the Corporation had 306.4 million common shares, 4.2 million stock options and 6.4 million equity-settled RSUs and equity-settled PSUs outstanding, and 4.0 million stock options exercisable.

11. 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, 2021. 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)	2021	2022	2023	2024	2025	Thereafter	Total
Commitments:							
Transportation and storage[1]	$ 294	$ 401	$ 446	$ 433	$ 409	$ 5,569	$ 7,552
Diluent purchases	150	20	17	—	—	—	187
Other operating commitments	16	16	15	13	12	37	109
Variable office lease costs	3	4	4	4	4	28	47
Capital commitments	18	—	—	—	—	—	18
Total Commitments	481	441	482	450	425	5,634	7,913
Other Obligations:							
Lease obligations	58	43	37	37	29	491	695
Long-term debt[2]	—	—	—	—	624	2,263	2,887
Interest on long-term debt[2]	144	192	192	192	156	260	1,136
Decommissioning obligation[3]	2	4	5	4	4	780	799
Obligations	**$ 685**	**$ 680**	**$ 716**	**$ 683**	**$ 1,238**	**$ 9,428**	**$ 13,430**

(1) This represents transportation and storage commitments from 2021 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, 2021.

(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.

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility in Alberta. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation filed a statement of defense in the first quarter of 2018. The Corporation continues to view this claim as without merit and will continue to defend against this claim. The Corporation believes that any liabilities that might arise from this matter are unlikely to have a material effect on its financial position.

12. NON-GAAP MEASURES

Cash operating netback is a non-GAAP measure. 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 measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to fund future capital expenditures. The Corporation's cash operating netback is calculated by deducting the related cost of diluent, blend purchases, transportation and storage, third-party curtailment credits, operating expenses, royalties and realized commodity risk management gains or losses from blend sales and power revenue. The per barrel calculation of cash operating netback is based on bitumen sales volume.

13. 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, 2020.

14. 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.

15. 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.

16. 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.

17. 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
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

18. ADVISORY

Forward-Looking Information

This document may contain forward-looking information within the meaning of applicable securities laws. This forward-looking information is identified by words such as "anticipate", "believe", "could", "drive", "expect", "estimate", "focus", "forward", "future", "guidance", "may", "on track", "outlook", "plan", "position", "potential", "priority", "should", "strategy", "target", "will", "would" or similar expressions and includes statements about future outcomes, including but not limited to: the Corporation's actions taken to ensure the health and safety of its personnel and business partners and the safe and reliable operation of the Christina Lake facility; the Corporation's climate-related goals, including achieving net zero carbon emissions by 2050; future production, revenues, expenses, cash flow, operating costs, steam-oil ratios, pricing differentials, reliability, profitability and capital expenditures; actions taken to respond to the impact of reduced use of fossil fuels and addressing risks arising out of climate change concerns; the Corporation's 2021 guidance, including full year 2021 production, non-energy operating costs, general and administrative costs, capital expenditures and total transportation costs; commodity prices; estimates of reserves and resources; anticipated sources of funding for operations and capital expenditures; anticipated regulatory approvals; and the Corporation's hedge book. Such forward-looking information is based on management's expectations and assumptions regarding future growth, results of operations, production, future capital and other expenditures, competitive advantage, plans for and results of drilling activity, environmental matters, and business prospects and opportunities.

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, 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; 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; 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; 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.

Non-GAAP Financial Measures

Certain financial measures in this MD&A do not have a standardized meaning as prescribed by IFRS. Cash operating netback is a non-GAAP financial measure. 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. This measure is presented and described in order to provide shareholders and potential investors with additional measures in understanding the Corporation's ability to generate funds and to finance its operations as well as profitability measures specific to the oil industry. The definition of this non-GAAP measure is presented in the "NON-GAAP MEASURES" section of this MD&A.

19. 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.

20. QUARTERLY SUMMARIES

	2021	2020				2019		
Unaudited	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**(17)**	16	(9)	(80)	(284)	26	24	(64)
Per share, diluted	**(0.06)**	0.05	(0.03)	(0.26)	(0.95)	0.09	0.08	(0.21)
Adjusted funds flow	**127**	84	26	89	76	156	191	227
Per share, diluted	**0.41**	0.27	0.09	0.29	0.25	0.51	0.63	0.75
Capital expenditures	**70**	40	36	20	54	72	40	33
Cash and cash equivalents	**54**	114	49	120	62	206	154	399
Working capital	**8**	55	131	173	371	123	204	416
Long-term debt	**2,852**	2,912	3,030	3,096	3,212	3,123	3,257	3,582
Shareholders' equity	**3,491**	3,506	3,495	3,507	3,593	3,853	3,828	3,795
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**57.84**	42.66	40.93	27.85	46.17	56.96	56.45	59.82
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.47)**	(9.30)	(9.09)	(11.47)	(20.53)	(15.83)	(12.24)	(10.67)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(14.22)**	(10.56)	(10.48)	(13.44)	(22.78)	(18.44)	(14.52)	(12.32)
AWB – Edmonton (US$/bbl)	**43.62**	32.10	30.45	14.41	23.39	38.52	41.93	47.50
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(2.52)**	(2.83)	(3.20)	(7.29)	(5.74)	(5.25)	(2.50)	1.64
AWB – U.S. Gulf Coast (US$/bbl)	**55.32**	39.83	37.73	20.56	40.43	51.71	53.95	61.46
C$ equivalent of 1US$ – average	**1.2663**	1.3031	1.3316	1.3860	1.3445	1.3201	1.3207	1.3376
Natural gas – AECO ($/mcf)	**3.43**	2.88	2.48	2.21	2.26	2.70	0.95	1.12
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	**128,236**	136,623	93,479	100,980	142,380	134,932	132,455	137,120
Diluent usage – bbls/d	**(40,938)**	(40,892)	(25,910)	(30,583)	(45,166)	(40,585)	(37,463)	(42,000)
Bitumen sales – bbls/d	**87,298**	95,731	67,569	70,397	97,214	94,347	94,992	95,120
Bitumen production – bbls/d	**90,842**	91,030	71,516	75,687	91,557	94,566	93,278	97,288
Steam-oil ratio (SOR)	**2.37**	2.31	2.36	2.32	2.31	2.27	2.26	2.16
Blend sales	**61.28**	45.75	45.44	20.96	36.46	56.55	60.26	69.19
Cost of diluent	**(8.94)**	(7.11)	(5.76)	(10.78)	(17.01)	(9.69)	(6.89)	(6.96)
Bitumen realization	**52.34**	38.64	39.68	10.18	19.45	46.86	53.37	62.23
Transportation and storage – net	**(11.41)**	(14.11)	(18.55)	(11.77)	(8.63)	(10.75)	(10.57)	(10.80)
Third-party curtailment credits	**—**	0.03	—	—	0.18	(0.21)	(0.37)	(0.89)
Royalties	**(0.85)**	(0.23)	(0.21)	(0.05)	(0.63)	(1.18)	(1.54)	(2.06)
Non-energy operating costs	**(4.05)**	(4.70)	(3.96)	(4.09)	(4.57)	(4.49)	(4.22)	(4.53)
Energy operating costs	**(4.34)**	(3.73)	(3.17)	(3.00)	(3.15)	(2.95)	(1.51)	(1.78)
Power revenue	**3.14**	1.45	1.08	0.95	2.21	1.57	1.43	1.65
Realized gain (loss) on commodity risk management	**(8.80)**	1.31	1.71	33.62	11.97	(0.52)	(4.15)	(5.94)
Cash operating netback	**26.03**	18.66	16.58	25.84	16.83	28.33	32.44	37.88
Power sales price (C$/MWh)	**93.27**	46.34	39.03	28.34	69.39	49.61	50.30	55.33
Power sales (MW/h)	**128**	125	78	98	129	124	112	118
Average cost of diluent ($/bbl of diluent)	**80.34**	62.37	60.48	45.76	73.09	79.07	77.71	84.95
Average cost of diluent as a % of WTI	**110 %**	112 %	111 %	119 %	118 %	105 %	104 %	106 %
Depletion and depreciation rate per bbl of production	**13.15**	12.64	13.33	13.55	14.83	13.18	13.43	41.22
General and administrative expense per bbl of production	**1.77**	1.65	1.50	1.29	1.96	2.25	1.66	1.81
COMMON SHARES								
Shares outstanding, end of period (000)	**303,137**	302,681	302,657	302,645	299,547	299,508	299,288	299,207
Common share price ($) - close (end of period)	**6.53**	4.45	2.77	3.77	1.67	7.39	5.80	5.02

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

- fluctuations in blend sales pricing due to significant changes in the price of WTI with periods of significant volatility in 2020, which has ranged from a quarterly average of US$27.85/bbl to US$59.82/bbl, and the differential between WTI and the Corporation's AWB at Edmonton, which has ranged from a quarterly average of US$10.48/bbl to US$22.78/bbl driven by supply/demand fundamentals;
- beginning in early March 2020, followed by a slow recovery through the second half of 2020 and continued uncertainty, global crude oil prices experienced multi-decade lows coupled with extreme levels of volatility driven primarily by an unprecedented reduction in global demand due to COVID-19;
- 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 commodity risk management contracts;
- Alberta Government enacted curtailment rules;
- changes in depletion and depreciation expense as a result of changes in production rates, future development costs and uncertainty of future benefits associated with specific non-core assets;
- exploration expense associated with discontinued exploration and evaluation activities in certain non-core growth properties;
- a decrease in general and administrative expense and non-energy costs due to reduction in staffing levels, and various non-recurring cost reductions in 2020 and 2021;
- 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.

21. ANNUAL SUMMARIES

	2020	2019	2018[(1)]	2017[(1)]	2016[(1)]	2015[(1)]	2014[(1)]
FINANCIAL *($millions unless specified)*							
Net earnings (loss)	(357)	(62)	(119)	166	(429)	(1,170)	(106)
Per share, diluted	(1.18)	(0.21)	(0.40)	0.57	(1.90)	(5.21)	(0.47)
Adjusted funds flow	275	724	175	371	(63)	49	790
Per share, diluted	0.90	2.41	0.58	1.28	(0.28)	0.22	3.51
Capital expenditures	149	198	622	502	140	314	1,314
Cash and cash equivalents	114	206	318	464	156	408	656
Working capital	55	123	290	313	96	363	526
Long-term debt	2,912	3,123	3,740	4,668	5,053	5,190	4,350
Shareholders' equity	3,506	3,853	3,886	3,964	3,287	3,678	4,768
BUSINESS ENVIRONMENT							
Average Benchmark Commodity Prices:							
WTI (US$/bbl)	39.40	57.03	64.77	50.95	43.33	48.80	93.00
Differential – WTI:WCS – Edmonton (US$/bbl)	(12.60)	(12.76)	(26.31)	(11.98)	(13.84)	(13.52)	(19.40)
Differential – WTI:AWB – Edmonton (US$/bbl)	(14.32)	(14.95)	(29.99)	(14.09)	(16.40)	(16.69)	(23.58)
AWB – Edmonton (US$/bbl)	25.08	42.08	34.78	36.86	26.93	32.11	69.42
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	(4.77)	(1.77)	(6.68)	(7.61)	(11.53)	(8.53)	(10.08)
AWB - U.S. Gulf Coast (US$/bbl)	34.63	55.26	58.09	43.34	31.80	40.27	82.92
C$ equivalent of 1US$ – average	1.3413	1.3269	1.2962	1.2980	1.3256	1.2788	1.1047
Natural gas – AECO ($/mcf)	2.43	1.92	1.62	2.29	2.25	2.71	4.50
OPERATIONAL **($/bbl unless specified)**							
Blend sales, net of purchased product – bbls/d	118,347	134,223	125,368	115,766	116,586	117,132	97,334
Diluent usage – bbls/d	(35,626)	(40,637)	(38,317)	(35,766)	(36,159)	(36,167)	(30,092)
Bitumen sales – bbls/d	82,721	93,586	87,051	80,000	80,427	80,965	67,242
Bitumen production – bbls/d	82,441	93,082	87,731	80,774	81,245	80,025	71,186
Steam-oil ratio (SOR)	2.32	2.22	2.19	2.31	2.29	2.47	2.48
Blend sales	37.65	61.29	53.47	51.39	38.19	42.14	76.11
Cost of diluent	(10.42)	(8.08)	(16.78)	(9.36)	(10.28)	(11.43)	(13.35)
Bitumen realization	27.23	53.21	36.69	42.03	27.91	30.71	62.76
Transportation and storage – net	(12.92)	(10.84)	(8.42)	(6.89)	(6.46)	(4.82)	(1.38)
Third-party curtailment credits	0.06	(0.37)	—	—	—	—	—
Royalties	(0.31)	(1.30)	(1.20)	(0.77)	(0.29)	(0.70)	(4.36)
Non-energy operating costs	(4.38)	(4.61)	(4.62)	(4.62)	(5.62)	(6.54)	(8.02)
Energy operating costs	(3.29)	(2.38)	(1.98)	(2.98)	(3.01)	(3.84)	(6.30)
Power revenue	1.49	1.75	1.51	0.76	0.64	0.99	2.26
Realized gain (loss) on commodity risk management	11.34	(3.31)	(4.37)	(0.39)	0.08	—	—
Cash operating netback	19.22	32.15	17.61	27.14	13.25	15.80	44.96
Power sales price (C$/MWh)	47.81	56.70	47.87	21.49	18.74	27.48	48.83
Power sales (MW/h)	108	121	114	118	115	121	129
Average cost of diluent ($/bbl of diluent)	61.86	79.89	91.60	72.32	61.06	67.72	105.94
Average cost of diluent as a % of WTI	117 %	106 %	109 %	109 %	106 %	109 %	103 %
Depletion and depreciation rate per bbl of production	13.60	20.90	14.12	16.13	16.81	16.00	14.57
General and administrative expense per bbl of production	1.62	1.99	2.58	2.94	3.24	4.06	4.29
COMMON SHARES							
Shares outstanding, end of period (000)	302,681	299,508	296,841	294,104	226,467	224,997	223,847
Common share price ($) - close (end of period)	4.45	7.39	7.71	5.14	9.23	8.02	19.55

(1) *The Corporation adopted IFRS 16 Leases, effective January 1, 2019, therefore prior periods have not been restated.*

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

As at	Note	March 31, 2021	December 31, 2020
Assets			
Current assets			
Cash and cash equivalents	14	**$ 54**	$ 114
Trade receivables and other		**397**	281
Inventories		**130**	96
Risk management	16	**16**	6
		597	497
Non-current assets			
Property, plant and equipment	3	**5,971**	5,993
Exploration and evaluation assets	4	**125**	125
Other assets	5	**199**	206
Risk management	16	**21**	21
Deferred income tax asset		**400**	382
Total assets		**$ 7,313**	$ 7,224
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 387**	$ 279
Interest payable		**35**	78
Current portion of provisions and other liabilities	7	**51**	56
Risk management	16	**116**	29
		589	442
Non-current liabilities			
Long-term debt	6	**2,852**	2,912
Provisions and other liabilities	7	**381**	364
Total liabilities		**3,822**	3,718
Shareholders' equity			
Share capital	8	**5,464**	5,460
Contributed surplus		**178**	177
Deficit		**(2,175)**	(2,158)
Accumulated other comprehensive income		**24**	27
Total shareholders' equity		**3,491**	3,506
Total liabilities and shareholders' equity		**$ 7,313**	$ 7,224

Commitments and contingencies (Note 18)

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

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

Three months ended March 31	Note	2021	2020
Revenues			
Petroleum revenue, net of royalties	10	**$ 886**	$ 642
Other revenue	10	**28**	23
Total revenues		**914**	665
Expenses			
Diluent and transportation	11	**389**	380
Operating expenses		**66**	68
Inventory impairment	5	**6**	29
Purchased product		**185**	176
Production curtailment credits purchased (sold)		**—**	(2)
Depletion and depreciation	3, 5	**108**	124
Exploration expense	4	**—**	366
General and administrative		**14**	16
Stock-based compensation	9	**2**	(13)
Net finance expense	13	**66**	70
Other expenses		**—**	2
Commodity risk management (gain) loss, net	16	**157**	(535)
Foreign exchange (gain) loss, net	12	**(43)**	270
Loss before income taxes		**(36)**	(286)
Income tax expense (recovery)		**(19)**	(2)
Net loss		**(17)**	(284)
Other comprehensive income (loss), net of tax			
Items that may be reclassified to profit or loss:			
Foreign currency translation adjustment		**(3)**	18
Comprehensive loss		**$ (20)**	$ (266)
Net loss per common share			
Basic	15	**$ (0.06)**	$ (0.95)
Diluted	15	**$ (0.06)**	$ (0.95)

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

Consolidated Statement of Changes in Shareholders' Equity
(Unaudited, expressed in millions of Canadian dollars)

	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2020	**$ 5,460**	**$ 177**	**$ (2,158)**	**$ 27**	**$ 3,506**
Stock-based compensation	**—**	**2**	**—**	**—**	**2**
Stock options exercised	**4**	**(1)**	**—**	**—**	**3**
Comprehensive income (loss)	**—**	**—**	**(17)**	**(3)**	**(20)**
Balance as at March 31, 2021	**$ 5,464**	**$ 178**	**$ (2,175)**	**$ 24**	**$ 3,491**
Balance as at December 31, 2019	$ 5,443	$ 182	$ (1,801)	$ 29	$ 3,853
Stock-based compensation	—	6	—	—	6
Comprehensive income (loss)	—	—	(284)	18	(266)
Balance as at March 31, 2020	$ 5,443	$ 188	$ (2,085)	$ 47	$ 3,593

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

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

Three months ended March 31	Note	2021	2020
Cash provided by (used in):			
Operating activities			
Net loss		**$ (17)**	$ (284)
Adjustments for:			
Deferred income tax expense (recovery)		**(19)**	(2)
Inventory Impairment	5	**6**	29
Depletion and depreciation	3, 5	**108**	124
Exploration expense	4	**—**	366
Stock-based compensation	9	**(8)**	5
Unrealized net (gain) loss on foreign exchange	12	**(43)**	267
Unrealized net (gain) loss on commodity risk management	16	**88**	(429)
Amortization of debt discount and debt issue costs	6	**2**	2
Gain on asset dispositions		**—**	(6)
Other		**1**	2
Decommissioning expenditures	7	**(2)**	(2)
Payments on onerous contracts	7	**(6)**	—
Net change in other liabilities		**11**	(3)
Funds flow from operating activities		**121**	69
Net change in non-cash working capital items	14	**(109)**	30
Net cash provided by (used in) operating activities		**12**	99
Investing activities			
Capital expenditures	3	**(70)**	(54)
Net proceeds on dispositions	5	**—**	6
Net change in non-cash working capital items	14	**21**	(11)
Net cash provided by (used in) investing activities		**(49)**	(59)
Financing activities			
Issuance of senior unsecured notes	6	**769**	1,581
Repayment and redemption of long-term debt	6	**(763)**	(1,723)
Debt redemption premium and refinancing costs	6	**(19)**	(48)
Issue of shares, net of issue costs		**2**	—
Receipts on leased assets	14	**1**	—
Payments on leased liabilities	14	**(7)**	(6)
Net cash provided by (used in) financing activities		**(17)**	(196)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(6)**	12
Change in cash and cash equivalents		**(60)**	(144)
Cash and cash equivalents, beginning of period		**114**	206
Cash and cash equivalents, end of period		**$ 54**	**$ 62**

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

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange under the symbol "MEG". The Corporation owns a 100% interest in over 400 square miles of mineral leases in the southern Athabasca oil region of Alberta, Canada and is primarily engaged in sustainable *in situ* thermal oil production at its Christina Lake Project.

The corporate office is located at 600 – 3rd Avenue SW, Calgary, Alberta, Canada.

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements ("interim consolidated financial statements") were prepared using the same accounting policies and methods as those used in the Corporation's audited consolidated financial statements for the year ended December 31, 2020. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting ("IAS 34"). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board ("IASB"), has been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 4 of the Corporation's audited consolidated financial statements for the year ended December 31, 2020. These interim consolidated financial statements should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2020.

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of coronavirus ("COVID-19"). COVID-19 continues to impact worldwide demand for crude oil and therefore global commodity markets. Price volatility remains largely due to market sensitivity to COVID-19 related news including vaccine breakthroughs and rollouts, and the resurgence of COVID-19 cases and developing variants of concern.

The continued impact on capital and financial markets on a macro-scale present uncertainty and risk with respect to the Corporation's performance, and estimates and assumptions used in the preparation of its financial results.

These interim consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation's functional currency and were approved by the Corporation's Audit Committee on May 3, 2021.

3. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Right-of-use assets	Corporate assets	Total
Cost					
Balance as at December 31, 2020	$ 9,245	$ 88	$ 296	$ 78	$ 9,707
Additions	71	—	8	—	79
Change in decommissioning liabilities	6	—	—	—	6
Balance as at March 31, 2021	**$ 9,322**	**$ 88**	**$ 304**	**$ 78**	**$ 9,792**
Accumulated depletion and depreciation					
Balance as at December 31, 2020	$ 3,580	$ 32	$ 53	$ 49	$ 3,714
Depletion and depreciation	100	—	6	1	107
Balance as at March 31, 2021	**$ 3,680**	**$ 32**	**$ 59**	**$ 50**	**$ 3,821**
Carrying amounts					
Balance as at December 31, 2020	$ 5,665	$ 56	$ 243	$ 29	$ 5,993
Balance as at March 31, 2021	**$ 5,642**	**$ 56**	**$ 245**	**$ 28**	**$ 5,971**

As at March 31, 2021, property, plant and equipment was assessed for impairment and no impairment was recognized. Included in the cost of property, plant and equipment is $247 million of assets under construction as at March 31, 2021 (December 31, 2020 – $244 million).

4. EXPLORATION AND EVALUATION ASSETS

As at March 31, 2021, exploration and evaluation assets consist of $125 million in exploration projects which are pending the determination of proved or probable reserves. These assets were assessed for impairment and no impairment has been recognized on exploration and evaluation assets.

5. OTHER ASSETS

As at	March 31, 2021	December 31, 2020
Non-current pipeline linefill[a]	**$ 171**	$ 176
Finance sublease receivables	**16**	17
Intangible assets[b]	**7**	7
Deferred financing costs	**2**	3
Prepaid transportation costs[c]	**8**	8
	204	211
Less current portion, included in trade receivables and other	**(5)**	(5)
	$ 199	$ 206

a. Non-current pipeline linefill on third-party owned pipelines is classified as a non-current asset as these transportation contracts expire between the years 2025 and 2048. During the three months ended March 31, 2021, an impairment of $6 million was recognized on long-term linefill.

b. As at March 31, 2021, intangible assets consist of software that is not an integral component of the related computer hardware. Depreciation of $0.4 million was recognized for the three months ended March 31, 2021 (year ended December 31, 2020 – $2 million). In 2020, the Corporation sold patents that were recorded at a nominal amount, and recognized a gain on asset disposition of $6 million.

c. Prepaid transportation costs related to upgrading third-party transportation infrastructure have been capitalized and are being amortized to transportation expense over the 30-year term of the agreement.

6. LONG-TERM DEBT

As at	March 31, 2021	December 31, 2020
Second Lien:		
6.5% senior secured second lien notes (March 31, 2021 - US$496 million; December 31, 2020 - US$496 million; due 2025)	**$ 624**	$ 633
Unsecured:		
7.125% senior unsecured notes (March 31, 2021 - US$1.2 billion; December 31, 2020 - US$1.2 billion; due 2027)	**1,509**	1,531
5.875% senior unsecured notes (March 31, 2021 - US$600 million; December 31, 2020 - US$nil; due 2029)	**754**	—
7.0% senior unsecured notes (March 31, 2021 - US$nil; December 31, 2020 - US$600 million; due 2024)	**—**	765
	2,887	2,929
Less:		
Debt redemption premium	**—**	9
Unamortized deferred debt discount and debt issue costs	**(35)**	(26)
	$ 2,852	$ 2,912

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2572 (December 31, 2020 – US$1 = C$1.2755).

On February 2, 2021, the Corporation successfully closed on a private offering of US$600 million in aggregate principal amount of 5.875% senior unsecured notes due February 2029. The net proceeds of the offering, together with cash-on-hand, were used to fully redeem US$600 million in aggregate principal amount of its 7.00% senior unsecured notes due March 2024 at a redemption price of 101.167% and to pay fees and expenses related to the offer. The redemption included a prepayment option, recognized as at December 31, 2020, whereby the Corporation was required to make an estimate at the reporting date of the likelihood of the prepayment option being exercised.

As at March 31, 2021, the Corporation had $785 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 year ended December 31, 2020 that remains outstanding.

7. PROVISIONS AND OTHER LIABILITIES

As at	March 31, 2021	December 31, 2020
Lease liabilities[(a)]	**$ 287**	$ 286
Decommissioning provision[(b)]	**103**	96
Onerous contract provision[(c)]	**18**	25
Long-term incentive compensation liability[(d)]	**24**	13
Provisions and other liabilities	**432**	420
Less current portion	**(51)**	(56)
Non-current portion	**$ 381**	$ 364

a. Lease liabilities:

As at		March 31, 2021		December 31, 2020
Balance, beginning of period	**$**	**286**	$	281
Additions		**8**		19
Modifications		**—**		7
Payments		**(13)**		(47)
Interest expense		**6**		26
Balance, end of period		**287**		286
Less current portion		**(28)**		(28)
Non-current portion	**$**	**259**	$	258

The Corporation's minimum lease payments are as follows:

As at March 31		2021
Within one year	**$**	**53**
Later than one year but not later than five years		**151**
Later than five years		**491**
Minimum lease payments		**695**
Amounts representing finance charges		**(408)**
Net minimum lease payments	**$**	**287**

b. Decommissioning provision:

The following table presents the decommissioning provision associated with the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets:

As at		March 31, 2021		December 31, 2020
Balance, beginning of period	**$**	**96**	$	71
Changes in estimated life and estimated future cash flows		**2**		4
Changes in discount rates		**5**		16
Liabilities settled		**(2)**		(3)
Accretion		**2**		8
Balance, end of period		**103**		96
Less current portion		**(5)**		(3)
Non-current portion	**$**	**98**	$	93

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The total undiscounted amount of the estimated future cash flows to settle the decommissioning obligations is $799 million (December 31, 2020 – $802 million). As at March 31, 2021, the Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 11.0% (December 31, 2020 – 11.7%) and an inflation rate of 2.1% (December 31, 2020 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2066 (December 31, 2020 - periods up to the year 2066).

c. Onerous contract provision:

The provision represents the present value of the minimum future payments that the Corporation is obligated to make under the non-cancelable onerous contract. There is no impact from discounting as the onerous contract will be settled by December 31, 2021. Liabilities settled during the three months ended March 31, 2021 were $6 million.

d. Long-term incentive compensation liability:

An $19 million cash-settled expense was recognized in the three months ended March 31, 2021 due to the increase in the Corporation's share price, and associated increase in value of cash-settled RSUs, PSUs and DSUs compared to December 31, 2020, which translates to an increased liability and expense at March 31, 2021.

8. SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares.

Changes in issued common shares are as follows:

	Three months ended March 31, 2021			Year ended December 31, 2020		
	Number of shares (thousands)		**Amount**	**Number of shares (thousands)**		**Amount**
Balance, beginning of year	**302,681**	**$**	**5,460**	299,508	$	5,443
Issued upon exercise of stock options	**456**		**4**	39		—
Issued upon vesting and release of RSUs and PSUs	**—**		**—**	3,134		17
Balance, end of period	**303,137**	**$**	**5,464**	302,681	$	5,460

9. STOCK-BASED COMPENSATION

Three months ended March 31		**2021**		**2020**
Cash-settled expense (recovery)(i)	**$**	**19**	$	(18)
Equity-settled expense		**2**		5
Equity price risk management (gain) loss(ii)		**(19)**		—
Stock-based compensation	**$**	**2**	$	(13)

(i) *Cash-settled RSUs and PSUs are accounted for as liability instruments and are measured at fair value based on the market value of the Corporation's common shares at each period end and certain estimates including a performance multiplier for PSUs. Fluctuations in the fair value are recognized during the period in which they occur.*

(ii) *Relates to financial derivatives entered into to manage the Corporation's exposure to cash-settled RSUs and 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 note 16(d) for further details.*

A $19 million cash-settled expense was recognized in the three months ended March 31, 2021 due to the increase in the Corporation's share price, and associated increase in value of cash-settled RSUs, PSUs and DSUs compared to December 31, 2020, which translates to an increased liability and expense at March 31, 2021. As at March 31, 2021, the Corporation recognized a liability of $43 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2020 – $23 million). The current portion of $19 million is included within accounts payable and accrued liabilities and $24 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards.

10. REVENUES

Three months ended March 31		2021		2020
Sales from:				
Production	**$**	**695**	$	469
Purchased product(i)		**198**		179
Petroleum revenue	**$**	**893**	$	648
Royalties		**(7)**		(6)
Petroleum revenue, net of royalties	**$**	**886**	$	642
Power revenue	**$**	**25**	$	20
Transportation revenue		**3**		3
Other revenue	**$**	**28**	$	23
Total revenues	**$**	**914**	$	665

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

a. Disaggregation of revenue from contracts with customers

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

	Three months ended March 31					
	2021			2020		
	Petroleum Revenue			Petroleum Revenue		
	Proprietary	Third-party	Total	Proprietary	Third-party	Total
Country:						
Canada	**$ 391**	**$ —**	**$ 391**	$ 308	$ 31	$ 339
United States	**304**	**198**	**502**	161	148	309
	$ 695	**$ 198**	**$ 893**	$ 469	$ 179	$ 648

Other revenue recognized during the years ended March 31, 2021 and 2020 is attributed to Canada.

b. Revenue-related assets

The Corporation has recognized the following revenue-related assets in trade receivables and other:

As at		March 31, 2021		December 31, 2020
Petroleum revenue	**$**	**354**	$	249
Other revenue		**6**		4
Total revenue-related assets	**$**	**360**	$	253

Revenue-related receivables are typically settled within 30 days. As at March 31, 2021 and December 31, 2020, there was no material expected credit loss required against revenue-related receivables.

11. DILUENT AND TRANSPORTATION

Three months ended March 31	2021	2020
Diluent expense	$ 296	$ 300
Transportation and storage	93	80
Diluent and transportation	$ 389	$ 380

12. FOREIGN EXCHANGE (GAIN) LOSS, NET

Three months ended March 31	2021	2020
Unrealized foreign exchange (gain) loss on:		
Long-term debt	$ (48)	$ 278
US$ denominated cash and cash equivalents	5	(11)
Unrealized net (gain) loss on foreign exchange	(43)	267
Realized (gain) loss on foreign exchange	—	3
Foreign exchange (gain) loss, net	$ (43)	$ 270

C$ equivalent of 1 US$		
Beginning of period	1.2755	1.2965
End of period	1.2572	1.4120

13. NET FINANCE EXPENSE

Three months ended March 31	2021	2020
Interest expense on long-term debt	$ 58	$ 64
Interest expense on lease liabilities	6	6
Interest income	—	(2)
Net interest expense	64	68
Accretion on provisions	2	2
Net finance expense	$ 66	$ 70

14. SUPPLEMENTAL CASH FLOW DISCLOSURES

Three months ended March 31	2021	2020
Cash provided by (used in):		
Trade receivables and other	$ (118)	$ 165
Inventories	(34)	34
Accounts payable and accrued liabilities	107	(136)
Interest payable	(43)	(44)
	$ (88)	$ 19
Changes in non-cash working capital relating to:		
Operating	$ (109)	$ 30
Investing	21	(11)
	$ (88)	$ 19
Cash and cash equivalents:[(a)]		
Cash	$ 54	$ 62
Cash equivalents	—	—
	$ 54	$ 62
Cash interest paid	$ 96	$ 105

a. As at March 31, 2021, $31 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (March 31, 2020 – $45 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2572 (March 31, 2020 – US$1=C$1.4120).

The following table provides a reconciliation of assets and liabilities to cash flows arising from financing activities:

	Finance sublease receivables	Lease liabilities	Long-term debt
Balance as at December 31, 2020	$ 17	$ 286	$ 2,912
Financing cash flow changes:			
Receipts on leased assets	(1)	—	—
Payments on leased liabilities	—	(7)	—
Issuance of senior unsecured notes	—	—	769
Repayment and redemption of long-term debt	—	—	(763)
Debt redemption premium and refinancing costs	—	—	(19)
Other cash and non-cash changes:			
Lease liabilities settled	—	(6)	—
Lease liabilities incurred	—	8	—
Interest expense on lease liabilities	—	6	—
Unrealized (gain) loss on foreign exchange	—	—	(48)
Amortization of deferred debt discount and debt issue costs	—	—	1
Balance as at March 31, 2021	**$ 16**	**$ 287**	**$ 2,852**

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

15. NET EARNINGS (LOSS) PER COMMON SHARE

Three months ended March 31		2021		2020
Net loss	$	(17)	$	(284)
Weighted average common shares outstanding (millions)[(a)]		303		300
Dilutive effect of stock options, RSUs and PSUs (millions)[(b)]		—		—
Weighted average common shares outstanding – diluted (millions)		303		300
Net earnings (loss) per share, basic	$	(0.06)	$	(0.95)
Net earnings (loss) per share, diluted	$	(0.06)	$	(0.95)

a. Weighted average common shares outstanding for the three months ended March 31, 2021 includes 493,829 PSUs vested but not yet released (three months ended March 31, 2020 - 381,014 PSUs).

b. For the three months ended March 31, 2021, the Corporation incurred a net loss and therefore there was no dilutive effect of stock options, RSUs and PSUs. If the Corporation had recognized net earnings for the three months ended March 31, 2021, the dilutive effect of stock options, RSUs and PSUs would have been 6.1 million weighted average common shares (three months ended March 31, 2020 - 4.6 million weighted average common shares).

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments recognized on the consolidated balance sheet are comprised of cash and cash equivalents, trade receivables and other, risk management contracts, accounts payable and accrued liabilities, interest payable and long-term debt.

a. Fair values:

The carrying values of cash and cash equivalents, trade receivables and other, accounts payable and accrued liabilities and interest payable included on the consolidated balance sheet approximates the fair values of the respective assets and liabilities due to the short-term nature of those instruments.

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

As at	March 31, 2021				December 31, 2020			
		Carrying amount		Fair value		Carrying amount		Fair value
Recurring measurements:								
Financial assets								
Risk management contracts	$	37	$	37	$	27	$	27
Financial liabilities								
Long-term debt (Note 6)	$	2,887	$	2,976	$	2,929	$	3,019
Risk management contracts	$	116	$	116	$	29	$	29

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker. The fair value was determined based on estimates as at March 31, 2021 and is expected to fluctuate given the volatility in the debt and commodity price markets.

The fair value of risk management contracts is derived using third-party valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including forward prices for commodities, interest rate yield curves and foreign exchange rates. The observable inputs may be adjusted using certain methods, which include extrapolation to the end of the term of the contract.

b. Risk management:

The Corporation's risk management assets and liabilities consist of WTI and light-heavy differential swaps, and if entered into options, plus condensate swaps and equity swaps. The use of the financial risk management contracts is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes. Financial risk management contracts are measured at fair value, with gains and losses on re-measurement included in the consolidated statement of earnings and comprehensive income in the period in which they arise.

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

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

As at	**March 31, 2021**			**December 31, 2020**		
	Asset	**Liability**	**Net**	**Asset**	**Liability**	**Net**
Gross amount	**$ 37**	**$ (144)**	**$ (107)**	$ 27	$ (62)	$ (35)
Amount offset	**—**	**28**	**28**	—	33	33
Net amount	**$ 37**	**$ (116)**	**$ (79)**	$ 27	$ (29)	$ (2)
Current portion	**$ 16**	**$ (116)**	**$ (100)**	$ 6	$ (29)	$ (23)
Non-current portion	**21**	**—**	**21**	21	—	21
Net amount	**$ 37**	**$ (116)**	**$ (79)**	$ 27	$ (29)	$ (2)

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

As at March 31	**2021**	**2020**
Fair value of contracts, beginning of year	$ (2)	$ (77)
Fair value of contracts realized	69	106
Change in fair value of contracts	(146)	323
Fair value of contracts, end of period	**$ (79)**	$ 352

c. Commodity risk management:

The Corporation had the following financial commodity risk management contracts relating to crude oil sales and condensate purchases outstanding as at March 31, 2021:

As at March 31, 2021			
Crude Oil Sales Contracts[ii]	**Volumes (bbls/d)**[i]	**Term**	**Average Price (US$/bbl)**[i]
WTI[iii] Fixed Price	13,000	Apr 1, 2021 - Jun 30, 2021	$46.31
WTI:WCS[iv] Fixed Differential	28,000	Apr 1, 2021 - Jun 30, 2021	$(12.26)
WTI:WCS Fixed Differential	10,000	Jul 1, 2021 - Sep 30, 2021	$(11.05)
Enhanced Fixed Price with Sold Put Option			
WTI Fixed Price/Sold Put Option Strike Price	29,000	Apr 1, 2021 - Dec 31, 2021	$46.18 / $38.79
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	10,950	Apr 1, 2021 - Dec 31, 2021	$(10.37)
WTI:Mont Belvieu Fixed Differential	200	Jan 1, 2022 - Dec 31, 2022	$(11.30)
Natural Gas Purchase Contracts	**Volumes (GJ/d)**[i]	**Term**	**Average Price (C$/GJ)**[i]
AECO Fixed Price	37,500	Apr 1, 2021 - Dec 31, 2021	$2.60

(i) The volumes and prices in the above table represent averages for various contracts with differing terms and prices. The average prices for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.
(ii) Incremental to these crude oil sales contracts, the Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months.
(iii) West Texas Intermediate ("WTI") crude oil
(iv) Western Canadian Select ("WCS") crude oil blend

The Corporation did not enter into any financial commodity risk management contracts subsequent to March 31, 2021.

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

Three months ended March 31	**2021**	**2020**
Realized loss (gain) on commodity risk management	**$ 69**	$ (106)
Unrealized loss (gain) on commodity risk management	**88**	(429)
Commodity risk management (gain) loss, net	**$ 157**	$ (535)

The following table summarizes the sensitivity of the earnings (loss) before income tax impact of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place as at March 31, 2021:

Commodity	**Sensitivity Range**	**Increase**	**Decrease**
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	**$ (57)**	**$ 55**
Crude oil differential price [i]	± US$5.00 per bbl applied to WTI:WCS differential contracts	**$ 22**	**$ (22)**
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)**

(i) As the WCS differential is expressed as a discount to WTI, an increase in the differential results in a lower WCS price and a decrease in the differential results in a higher WCS price.

d. Equity price risk management:

The Corporation enters 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 and funds flow from operating activities are impacted when outstanding cash-settled RSUs and PSUs, issued under the Corporation's stock-based compensation plans, are revalued each period based on the Corporation’s share price. 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 to manage its exposure on cash-settled RSUs and PSUs vesting between 2021 and 2023.

	Three months ended March 31	
($millions)	**2021**	**2020**
Unrealized equity price risk management (gain) loss	**$ (11)**	$ —
Realized equity price risk management (gain) loss	**(8)**	—
Equity price risk management (gain) loss	**$ (19)**	$ —

e. Credit risk management:

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward looking information to determine the appropriate loss allowance provisions. Credit risk exposure is mitigated through the use of credit policies governing the Corporation’s credit portfolio and with credit practices that limit transactions according to each counterparty's credit quality. A substantial portion of accounts receivable are with investment grade customers in the energy industry and are subject to normal industry credit risk. The Corporation has experienced no material loss in relation to trade receivables. As at March 31, 2021, the Corporation’s estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $392 million. All amounts receivable from commodity risk management activities are due from large Canadian banks with strong investment grade credit ratings. Counterparty default risk associated with the Corporation’s commodity risk management activities is also partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in note 24 of the Corporation’s 2020 annual consolidated financial statements.

The Corporation’s cash balances are used to fund the development of its properties. As a result, the primary objectives of the investment portfolio are low risk capital preservation and high liquidity. The cash balances are held in high interest savings accounts or are invested in high grade, liquid, short-term instruments such as bankers’ acceptances, commercial paper, money market deposits or similar instruments. The cash and cash equivalents balance at March 31, 2021 was $54 million. None of the investments are past their maturity or considered impaired. The Corporation’s estimated maximum exposure to credit risk related to its cash and cash equivalents is $54 million.

f. Liquidity risk management:

Liquidity risk is the risk that the Corporation will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk that the Corporation cannot generate sufficient cash flow from the Christina Lake Project or is unable to raise further capital in order to meet its obligations under its debt agreements. The lenders are entitled to exercise any and all remedies available under the debt agreements. The Corporation manages its liquidity risk through the active management of cash, debt and revolving credit facilities and by maintaining appropriate access to credit.

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. Meeting current and future obligations through the uncertainty associated with COVID–19 is supported by the Corporation's financial framework including a strong commodity risk management program securing cash flow through 2021 and credit risk management policies minimizing exposure related to customer receivables primarily to investment grade customers in the energy industry. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary.

The Corporation's earliest maturing long-term debt is nearly four years out, represented by US$496 million of senior unsecured notes due January 2025. None of the Corporation's outstanding long-term debt contain financial maintenance covenants. 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.

17. CAPITAL MANAGEMENT

The Corporation's capital consists of cash and cash equivalents, debt and shareholders' equity. The Corporation's objective for managing capital is to prioritize balance sheet strength while maintaining flexibility to repay debt, fund sustaining capital, return capital to shareholders or fund future production growth. In the current price environment, 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. Debt repayment and sustaining capital expenditure activities are anticipated to be funded by the Corporation's adjusted funds flow, cash-on-hand and/or other available liquidity.

On February 2, 2021, the Corporation completed the refinancing and extension of the maturity profile of its debt portfolio. MEG's earliest maturity date on outstanding debt is January 2025. As at March 31, 2021, the Corporation had $785 million of unutilized capacity under the $800 million revolving credit facility and had $108 million of unutilized capacity under the $500 million letter of credit facility. A letter of credit of $15 million was issued under its revolving credit facility in the first quarter of 2020.

The following table summarizes the Corporation's net debt:

As at	Note	March 31, 2021	December 31, 2020
Long-term debt	10	**$ 2,852**	$ 2,912
Cash and cash equivalents		**(54)**	(114)
Net debt		**$ 2,798**	$ 2,798

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

On February 2, 2021, the Corporation successfully closed on a private offering of US$600 million in aggregate principal amount of 5.875% senior unsecured notes due February 2029. The net proceeds of the offering, together with cash-on-hand, were used to fully redeem US$600 million in aggregate principal amount of the 7.00% senior unsecured notes due March 2024 at a redemption price of 101.167% and to pay fees and expenses related to the offer.

The following table summarizes the Corporation's funds flow from (used in) operations and adjusted funds flow:

Three months ended March 31	Note	2021	2020
Net cash provided by (used in) operating activities		**$ 12**	$ 99
Net change in non-cash operating working capital items	14	**109**	(30)
Funds flow from (used in) operations		**121**	69
Adjustments:			
Payments on onerous contracts		**6**	—
Contract cancellation		**—**	7
Adjusted funds flow		**$ 127**	$ 76

Management utilizes funds flow from (used in) operations and adjusted funds flow as a measure to analyze operating performance and cash flow generating ability. Funds flow from (used in) operations and adjusted funds flow impacts the level and extent of debt repayment, funding for capital expenditures and returning capital to shareholders. By excluding changes in non-cash working capital and non-recurring items from cash flows, the funds flow from (used in) operations and adjusted funds flow measures provide meaningful metrics for management by establishing a clear link between the Corporation's cash flows and the operating netbacks from the Christina Lake Project. Funds flow from (used in) operations and adjusted funds flow are not intended to represent net cash provided by (used in) operating activities.

Net debt, funds flow from (used in) operations and adjusted funds flow are not standardized measures and may not be comparable with the calculation of similar measures by other companies.

18. COMMITMENTS AND CONTINGENCIES

a. Commitments

The Corporation’s commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at March 31, 2021:

	2021	2022	2023	2024	2025	Thereafter	Total
Transportation and storage(i)	$ 294	$ 401	$ 446	$ 433	$ 409	$ 5,569	$ 7,552
Diluent purchases	150	20	17	—	—	—	187
Other operating commitments	16	16	15	13	12	37	109
Variable office lease costs	3	4	4	4	4	28	47
Capital commitments	18	—	—	—	—	—	18
Commitments	**$ 481**	**$ 441**	**$ 482**	**$ 450**	**$ 425**	**$ 5,634**	**$ 7,913**

(i) This represents transportation and storage commitments from 2021 to 2048, including the Access Pipeline TSA, and pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet (Note 7(a)).

b. Contingencies

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

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility in Alberta. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation filed a statement of defense in the first quarter of 2018. The Corporation continues to view this claim as without merit and will continue to defend against all such claims. The Corporation believes that any liabilities that might arise from this matter are unlikely to have a material effect on its financial position.