MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three and nine months ended September 30, 2021 was approved by the Corporation's Audit Committee on November 8, 2021. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three and nine months ended September 30, 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.

MD&A - Table of Contents

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

During the third quarter of 2021, as previously announced, the Corporation continued to prioritize debt repayment with the August 23, 2021 redemption of US$100 million of the Corporation's 6.50% senior secured second lien notes due January 2025 at a redemption price of 103.25%, plus accrued and unpaid interest. Since 2018 the Corporation has repaid US$1.6 billion of outstanding indebtedness and remains committed to continued debt reduction as a key component of its capital allocation strategy.

The Corporation generated adjusted funds flow of $239 million in the third quarter of 2021 compared to $26 million in the third quarter of 2020. The increase is consistent with the macro environment where the significant increase in crude oil prices was supported by global energy demand recovery. The Corporation's realized blend sales price averaged $74.54 per barrel in the third quarter of 2021 compared to $45.44 per barrel in the third quarter of 2020 resulting primarily from a 72% increase in the WTI benchmark price. This was partially offset by the Corporation's losses on commodity price risk management contracts which were put in place in the second half of 2020 to protect the internal funding of the Corporation's 2021 capital program.

Production volumes averaged 91,506 barrels per day in the third quarter of 2021 compared to 71,516 barrels per day during the third quarter of 2020. Increased steam utilization, improved field reliability, completed and ongoing well optimization and recompletion work all contributed to strong field-wide production performance to date in 2021. Average bitumen production in the third quarter of 2020 was impacted by major planned turnaround activities at the Corporation's Phase 1 and 2 facilities.

The Corporation invested $84 million in the third quarter of 2021 compared to $36 million during the third quarter of 2020. The majority of the $84 million invested in the quarter was directed towards sustaining and maintenance activities as well as incremental well capital necessary to allow the Corporation to fully utilize the Christina Lake central plant facility's oil processing capacity of approximately 100,000 bbls/d, prior to any impact from scheduled maintenance activity or outages. As previously disclosed in the Corporation's second quarter 2021 release, the total investment for this optimization initiative is approximately $125 million with $75 million included in the 2021 capital investment budget and the remainder expected to be invested in the first half of 2022.

The Corporation recognized net earnings of $54 million in the third quarter of 2021 compared to a net loss of $9 million in the third quarter of 2020. Increased earnings were mainly due to stronger global crude oil prices.

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 operations at the Christina Lake facility. The Corporation continues to apply screening procedures, including antigen screening and other protocols, to ensure the health and safety of its people.

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:

	Nine months ended September 30		2021			2020				2019
($millions, except as indicated)	**2021**	**2020**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Bitumen production - bbls/d	**91,386**	**79,557**	**91,506**	91,803	90,842	91,030	71,516	75,687	91,557	94,566
Steam-oil ratio	**2.44**	**2.33**	**2.56**	2.39	2.37	2.31	2.36	2.32	2.31	2.27
Bitumen sales - bbls/d	**89,861**	**78,354**	**92,251**	89,980	87,298	95,731	67,569	70,397	97,214	94,347
Bitumen realization - $/bbl	**59.28**	**22.54**	**64.91**	60.09	52.34	38.64	39.68	10.18	19.45	46.86
Net operating costs - $/bbl(1)	**6.00**	**5.85**	**7.17**	5.54	5.25	6.98	6.05	6.14	5.51	5.87
Non-energy operating costs - $/bbl	**4.12**	**4.25**	**4.46**	3.84	4.05	4.70	3.96	4.09	4.57	4.49
Cash operating netback - $/bbl(2)	**31.71**	**19.45**	**37.31**	31.30	26.03	18.66	16.58	25.84	16.83	28.33
General & administrative expense $/bbl(3)	**1.68**	**1.61**	**1.72**	1.56	1.77	1.65	1.50	1.29	1.96	2.25
Adjusted funds flow(4)	**532**	**191**	**239**	166	127	84	26	89	76	155
Per share, diluted	**1.71**	**0.62**	**0.77**	0.53	0.41	0.27	0.09	0.29	0.25	0.51
Revenue	**3,014**	**1,505**	**1,091**	1,009	914	786	533	307	665	992
Net earnings (loss)	**105**	**(373)**	**54**	68	(17)	16	(9)	(80)	(284)	26
Per share, diluted	**0.34**	**(1.24)**	**0.17**	0.22	(0.06)	0.05	(0.03)	(0.26)	(0.95)	0.09
Capital expenditures	**224**	**109**	**84**	70	70	40	36	20	54	72
Cash and cash equivalents	**210**	**49**	**210**	159	54	114	49	120	62	206
Long-term debt - C$	**2,769**	**3,030**	**2,769**	2,820	2,852	2,912	3,030	3,096	3,212	3,123
Long-term debt - US$	**2,172**	**2,274**	**2,172**	2,273	2,268	2,283	2,274	2,274	2,275	2,409

(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 19 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 and opportunities presented by climate change and the energy transition and its commitment to taking appropriate actions. The Corporation's business strategy recognizes the importance and momentum behind the low carbon energy transition, recognizes the increasing demand for responsibly developed low carbon energy and addresses the risks arising out of climate change concerns. Although the timing and impact of the energy transition is highly indeterminate, the Corporation is focused on enhancing its position as a sustainable low-cost producer and achieving net zero carbon emissions.

In 2020, the Corporation set a long-term goal of reaching net zero Scope 1 and Scope 2 GHG emissions by 2050. In the third quarter of 2021, the Corporation adopted a mid-term target of reaching a 30% reduction in bitumen GHG emissions intensity (Scope 1 and Scope 2) from 2013 levels by 2030. In addition, the Corporation continued to advance its ESG activities and strategies with the development and implementation of an Indigenous Peoples Policy, including Indigenous Awareness Training, as well as an Inclusion and Diversity Policy and a Water Policy.

Also during the third quarter of 2021, the Corporation published its second ESG report on August 11, 2021.

The Corporation, along with five other oil sands operators that collectively represent about 95% of Canada's oil sands production, is part of the Oilsands Pathways to Net Zero ("Pathways") Alliance working collectively with the federal and Alberta governments to achieve net zero GHG emissions from oil sands operations by 2050. The Pathways alliance proposes to reduce oil sands production emissions in three phases: Phase 1 (2021-2030), Phase 2 (2031-2040) and Phase 3 (2041-2050). In Phase 1, the Pathways initiative will focus on building out a carbon capture network in the oil sands producing region of northern Alberta. A key aspect of this network is a proposed carbon transportation line to gather CO2 from more than 20 oil sands facilities and move it to a proposed hub in the Cold Lake area of Alberta for storage. The carbon transportation line would also be available to other industries in the region interested in capturing and storing CO2. The Pathways alliance is currently developing detailed project plans for Phase 1, including conducting feasibility studies for the transportation line and storage hub as well as pre-engineering work for capturing carbon at multiple oil sands facilities.

For further details on the Corporation's approach to ESG matters, please refer to the 2020 annual MD&A and most recently filed AIF on www.sedar.com.

4. NET EARNINGS (LOSS)

	Three months ended September 30		Nine months ended September 30	
($millions, except per share amounts)	**2021**	**2020**	**2021**	**2020**
Net earnings (loss)	**$ 54**	$ (9)	**$ 105**	$ (373)
Per share, diluted	**$ 0.17**	$ (0.03)	**$ 0.34**	$ (1.24)

The Corporation recognized net earnings of $54 million and $105 million for the three and nine months ended September 30, 2021, respectively, compared to a net loss of $9 million and $373 million during the same periods of 2020, respectively. Increased net earnings during the three months ended September 30, 2021 was primarily due to stronger global crude oil prices and a reduction in hedged volumes, partially offset by an unrealized foreign exchange loss as the Canadian dollar weakened relative to the U.S. dollar during the quarter, a settlement expense and higher depletion and depreciation expense due to increased production. Increased net earnings during the nine months ended September 30, 2021 was primarily due to stronger global crude oil prices partially offset by a commodity price risk management loss as a result of stronger forward commodity prices. The net loss during the nine months ended September 30, 2020 was impacted by the recognition of a $366 million exploration expense.

5. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended September 30		Nine months ended September 30	
	2021	**2020**	**2021**	**2020**
Bitumen production – bbls/d	**91,506**	71,516	**91,386**	79,557
Steam-oil ratio (SOR)	**2.56**	2.36	**2.44**	2.33

Bitumen Production

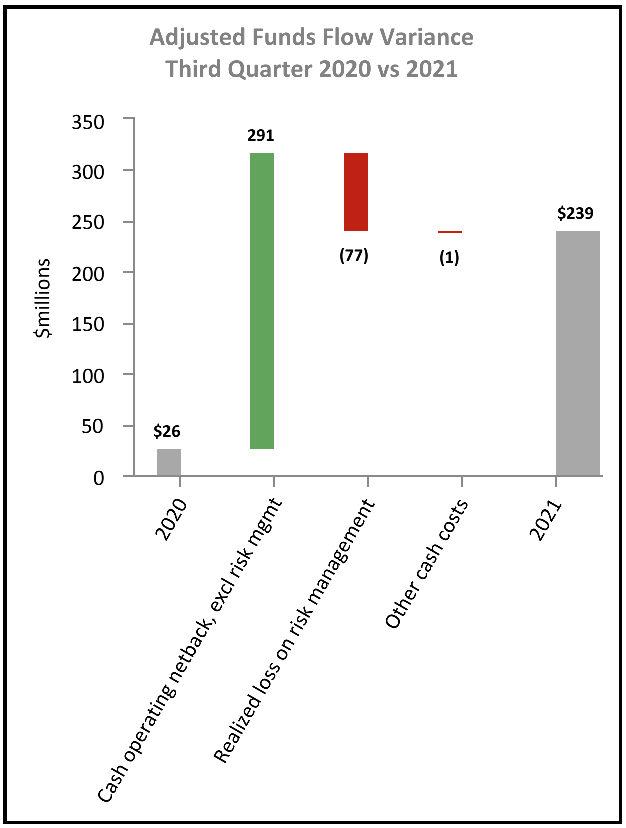
Bitumen production increased 28% during the three months ended September 30, 2021 compared to the same period of 2020. Targeted maintenance activities were completed during the three months ended September 30, 2021 with minimal impact to production. The Corporation was successful in shifting a large component of previously planned 2021 activities into the 75-day major planned turnaround in 2020. As a result of this shift, the Corporation saw reduced bitumen production during the three months ended September 30, 2020 due to the major planned turnaround at the Phase 1 and 2 facilities, which began in June 2020 and was completed mid-August 2020.

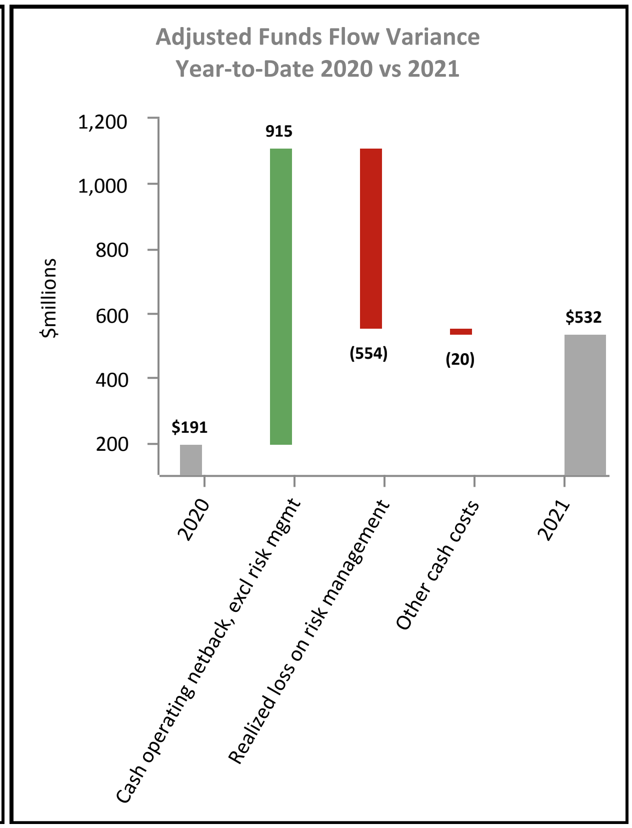
Bitumen production increased 15% during the nine months ended September 30, 2021 compared to the same period of 2020. Increased steam utilization, improved field reliability, completed and ongoing well optimization and recompletion work all contributed to strong field-wide production performance to date in 2021. This compares to reduced bitumen production in 2020 due to the major planned turnaround at the Phase 1 and 2 facilities, which began in June 2020 and was completed mid-August 2020, as well as voluntary price-related production curtailments in April and May 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 and nine months ended September 30, 2021, compared to the same periods 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 and nine months ended September 30, 2021, adjusted funds flow increased compared to the same periods 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 in the second half of 2020 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 September 30		Nine months ended September 30	
($millions)	**2021**	**2020**	**2021**	**2020**
Net cash provided by (used in) operating activities	**$ 257**	$ (31)	**$ 449**	$ 186
Net change in non-cash operating working capital items	**(45)**	50	**44**	(28)
Funds flow from operations	**212**	19	**493**	158
Adjustments:				
Settlement expense[(1)]	**21**	—	**21**	—
Payments on onerous contracts	**6**	—	**18**	—
Contract cancellation	**—**	7	**—**	33
Adjusted funds flow	**$ 239**	$ 26	**$ 532**	$ 191

(1) *During the third quarter of 2021, the Corporation reached an agreement to settle the litigation matter commenced in 2014 relating to legacy issues involving a unit train transloading facility in Alberta. Under the agreement, the Corporation paid (subsequent to the quarter) the sum of $21 million in full and final settlement of the claim and the claim has been discontinued.*

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 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.

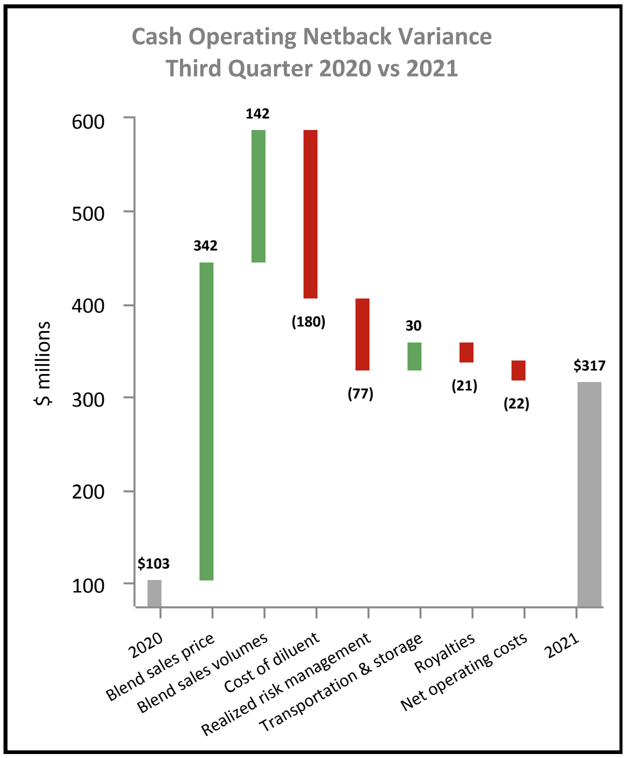
Cash Operating Netback

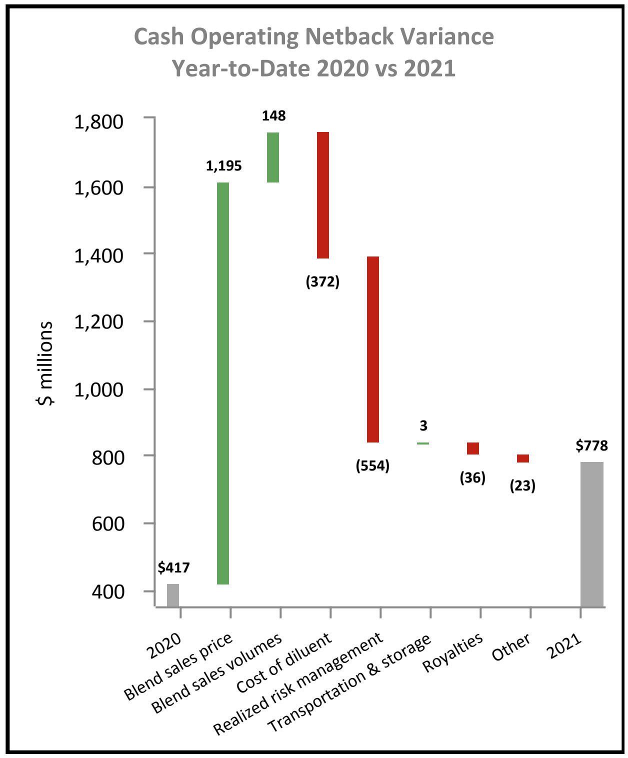
The following table summarizes the Corporation's cash operating netback. Unless otherwise indicated, the per barrel calculation for the periods indicated below are based on bitumen sales volume.

	Three months ended September 30				Nine months ended September 30			
	2021		**2020**		**2021**		**2020**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Sales from production	**$ 868**		$ 385		**$ 2,376**		$ 1,035	
Sales from purchased product[1]	**225**		140		**610**		437	
Petroleum revenue	**1,093**		525		**2,986**		1,472	
Purchased product[1]	**(218)**		(134)		**(587)**		(416)	
Blend sales[2]	**$ 875**	**$ 74.54**	$ 391	$ 45.44	**$ 2,399**	**$ 68.40**	$ 1,056	$ 34.34
Cost of diluent	**(324)**	**(9.63)**	(144)	(5.76)	**(944)**	**(9.12)**	(572)	(11.80)
Bitumen realization	**551**	**64.91**	247	39.68	**1,455**	**59.28**	484	22.54
Transportation and storage[3]	**(85)**	**(10.03)**	(115)	(18.55)	**(264)**	**(10.76)**	(267)	(12.44)
Third-party curtailment credits[4]	**—**	**—**	—	—	**—**	**—**	2	0.08
Royalties	**(23)**	**(2.67)**	(2)	(0.21)	**(44)**	**(1.77)**	(8)	(0.34)
Net operating costs	**(60)**	**(7.17)**	(38)	(6.05)	**(147)**	**(6.00)**	(126)	(5.85)
Cash operating netback - excluding realized commodity risk management	**383**	**45.04**	92	14.87	**1,000**	**40.75**	85	3.99
Realized gain (loss) on commodity risk management	**(66)**	**(7.73)**	11	1.71	**(222)**	**(9.04)**	332	15.46
Cash operating netback[5]	**$ 317**	**$ 37.31**	$ 103	$ 16.58	**$ 778**	**$ 31.71**	$ 417	$ 19.45
Bitumen sales volumes - bbls/d		**92,251**		67,569		**89,861**		78,354

(1) Sales and purchases of oil products related to marketing asset optimization activities.
(2) Blend sales per barrel are based on blend sales volumes.
(3) 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 marketing asset optimization activities undertaken in the period. Marketing asset optimization is focused on the recovery of fixed costs related to transportation and storage contracts during periods of underutilization of these assets, with the goal to strengthen cash operating netback. Marketing asset optimization activities consist of the purchase and sale of third-party products. The Corporation does not engage in speculative trading. The purchase and sale of third-party products to facilitate asset optimization activities requires the elimination of price risk pursuant to policies approved by the Corporation's Board of Directors which can be achieved either through the counterparty or through financial price risk management.





Bitumen Realization

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

	Three months ended September 30				Nine months ended September 30			
	2021		2020		2021		2020	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Sales from production	**$ 868**		$ 385		**$ 2,376**		$ 1,035	
Sales from purchased product[1]	**225**		140		**610**		437	
Petroleum revenue	**$ 1,093**		$ 525		**$ 2,986**		$ 1,472	
Purchased product[1]	**(218)**		(134)		**(587)**		(416)	
Blend sales[2]	**$ 875**	**$ 74.54**	$ 391	$ 45.44	**$ 2,399**	**$ 68.40**	$ 1,056	$ 34.34
Cost of diluent	**(324)**	**(9.63)**	(144)	(5.76)	**(944)**	**(9.12)**	(572)	(11.80)
Bitumen realization	**$ 551**	**$ 64.91**	$ 247	$ 39.68	**$ 1,455**	**$ 59.28**	$ 484	$ 22.54

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

Blend sales price increased by $29.10 per barrel and $34.06 per barrel during the three and nine months ended September 30, 2021, respectively, compared to the same periods of 2020. The increase in blend sales price during the three and nine months ended September 30, 2021 is primarily due to a higher WTI price.

During the three months ended September 30, 2021, the cost of diluent per barrel increased 67% compared to the same period of 2020 primarily due to wider WTI:AWB differentials. The cost of diluent during the three months ended September 30, 2020 reflected narrower WTI:AWB differentials and the use of lower priced diluent from inventory resulting in a higher recovery of the cost of diluent through blend sales.

During the nine months ended September 30, 2021, the cost of diluent per barrel decreased 23% compared to the same period of 2020. The decrease reflects narrower WTI:AWB differentials resulting in a higher recovery of the cost of diluent through blend sales. The cost of diluent during the nine months ended September 30, 2020 reflected the use of higher priced diluent from inventory resulting in a lower recovery of the cost of diluent through blend sales.

The total cost of diluent was $324 million and $944 million during the three and nine months ended September 30, 2021, respectively, compared to $144 million and $572 million during the same periods of 2020. This translates to a cost per barrel of diluent during the three and nine months ended September 30, 2021 of $99.69 and $89.67, respectively, compared to $60.48 and $61.65 for the same periods 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. The cost of diluent recognized is determined on a weighted-average cost basis and diluent volumes are typically held in inventory for 30 to 60 days. Approximately half of the diluent is sourced from each of Edmonton and Mont Belvieu, Texas. Refer to condensate prices within the "BUSINESS ENVIRONMENT" section of this MD&A for further details.

Transportation and Storage

The Corporation's marketing strategy focuses on maximizing its 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 September 30				Nine months ended September 30			
	2021		2020		2021		2020	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Transportation and storage	**$ (85)**	**$ (10.03)**	$ (115)	$ (18.55)	**$ (264)**	**$ (10.76)**	$ (267)	$ (12.44)
Bitumen sales volumes - bbls/d	**92,251**		67,569		**89,861**		78,354	

During the three and nine months ended September 30, 2021, total transportation and storage costs decreased compared to the same periods of 2020. Total transportation and storage costs during the three months ended September 30, 2021 were lower compared to the same period of 2020 due to lower blend sales volumes sold at the USGC resulting from significantly increased apportionment levels on the Enbridge mainline system. Total transportation and storage costs during the nine months ended September 30, 2021 decreased due to the elimination of rail transportation to the USGC in 2021 partially offset by higher blend sales volumes sold at the USGC, compared to the same period of 2020.

Transportation and storage costs on a per barrel basis decreased during the three and nine months ended September 30, 2021, compared to the same period of 2020, concurrent with the lower total transportation costs as well as the impact of spreading the costs over higher bitumen sales volumes.

The Corporation partially mitigated the cost of unutilized transportation and storage assets through the purchase and sale of non-proprietary product, or asset optimization activities, added $7 million, or $0.60 per barrel, to blend sales during the three months ended September 30, 2021 compared to $6 million, or $0.73 per barrel, during the same period of 2020. Optimization activities added $23 million, or $0.64 per barrel, to blend sales during the nine months ended September 30, 2021 compared to $21 million, or $0.68 per barrel, during the same period of 2020. 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. 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 September 30				Nine months ended September 30			
	2021		2020		2021		2020	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Royalties	**$ (23)**	**$ (2.67)**	$ (2)	$ (0.21)	**$ (44)**	**$ (1.77)**	$ (8)	$ (0.34)
WTI benchmark price (US$/bbl)		**$ 70.56**		$ 40.93		**$ 64.82**		$ 38.32

The increase in royalties for the three and nine months ended September 30, 2021, compared to the same periods of 2020, is primarily 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 September 30				Nine months ended September 30			
	2021		2020		2021		2020	
($millions, except as indicated)		$/bbl		$/bbl		$/bbl		$/bbl
Non-energy operating costs	**$ (38)**	**$ (4.46)**	$ (25)	$ (3.96)	**$ (101)**	**$ (4.12)**	$ (91)	$ (4.25)
Energy operating costs	**(40)**	**(4.77)**	(20)	(3.17)	**(110)**	**(4.46)**	(67)	(3.11)
Power revenue	**18**	**2.06**	7	1.08	**64**	**2.58**	32	1.51
Net operating costs	**$ (60)**	**$ (7.17)**	$ (38)	$ (6.05)	**$ (147)**	**$ (6.00)**	$ (126)	$ (5.85)
Bitumen sales volumes - bbls/d		**92,251**		67,569		**89,861**		78,354
Average delivered natural gas price (C$/mcf)		**$ 4.17**		$ 2.77		**$ 3.78**		$ 2.49
Average realized power sales price (C$/Mwh)		**$ 82.17**		$ 39.03		**$ 88.33**		$ 48.41

Non-energy operating costs increased for the three and nine months ended September 30, 2021, compared to the same periods of 2020. In the second and third quarter of 2020, the Corporation benefited from 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. In response to this collapse, the Corporation took measures to reduce costs through salary rollbacks, reductions in staffing levels and vendor concessions. Also during this time in 2020, a major planned turnaround at the Phase 1 and 2 facilities was undertaken which decreased production-related activities and costs. Many of the cost reductions that occurred in 2020 were temporary, and consistent with the improved price environment and increased production-related activities in 2021, costs have risen.

Energy operating costs increased predominantly due to the AECO natural gas market strengthening, as well as increased consumption as production increased. This was partially offset by the Alberta power market strengthening. Power revenue, which includes the impact of physical risk management contracts on power sales, offset energy operating costs by 45% and 58% during the three and nine months ended September 30, 2021, respectively, compared to 35% and 48% during the same periods of 2020, respectively.

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 September 30				Nine months ended September 30			
	2021		**2020**		**2021**		**2020**	
($millions, except as indicated)		**$/bbl**		**$/bbl**		**$/bbl**		**$/bbl**
Realized gain (loss) on commodity risk management	**$ (66)**	**$ (7.73)**	$ 11	$ 1.71	**$ (222)**	**$ (9.04)**	$ 332	$ 15.46

Realized losses recognized on commodity risk management contracts were recognized during the three and nine months ended September 30, 2021 primarily due to the increase in the WTI prices to date in 2021 compared to the WTI fixed price contracts in place. Conversely, realized gains were recognized during the three and nine months ended September 30, 2020 due to the significant weakening in the WTI prices 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 September 30, 2021**		
	Edmonton (US$/bbl)	**USGC (US$/bbl)**	**TOTAL (US$/bbl)**
(US$ per barrel of blend sales, unless otherwise indicated)	**Pipeline**	**Pipeline[3]**	
WTI - benchmark	$ 70.56	$ 70.56	$ 70.56
Differential - WTI:AWB at sales point	(15.88)	(5.33)	(11.89)
Asset optimization	—	1.26	0.48
Blend sales price	54.68	66.49	59.15
Transportation and storage[1]	(2.17)	(11.64)	(5.75)
Transportation and storage from Christina Lake to Edmonton[2]	2.17	2.17	2.17
Blend sales price, net of transportation & storage at Edmonton	$ 54.68	$ 57.02	$ 55.57
Total blend sales - bbls/d	79,281	48,265	127,546
% of total sales	62 %	38 %	100 %
	Edmonton (US$/bbl)	**USGC (US$/bbl)**	**USGC premium (US$/bbl)**
Average blend sales price by location	$ 54.68	$ 66.49	$ 11.81
Transportation and storage[1]	(2.17)	(11.64)	(9.47)
Transportation and storage from Christina Lake to Edmonton[2]	2.17	2.17	—
Blend sales price, net of transportation & storage at Edmonton	$ 54.68	$ 57.02	$ 2.34

Blend sales distribution by sales market	**Three months ended September 30, 2020**			
	Edmonton (US$/bbl)		**USGC (US$/bbl)**	**TOTAL (US$/bbl)**
(US$ per barrel of blend sales, unless otherwise indicated)	**Pipeline**	**Rail**	**Pipeline[3]**	
WTI - benchmark	$ 40.93	$ 40.93	$ 40.93	$ 40.93
Differential - WTI:AWB at sales point	(10.73)	(20.52)	(3.05)	(7.35)
Asset optimization	—	—	0.88	0.55
Blend sales price	30.20	20.41	38.76	34.13
Transportation and storage[1]	(2.36)	(6.32)	(13.88)	(10.07)
Transportation and storage from Christina Lake to Edmonton[2]	2.36	2.36	2.36	2.36
Blend sales price, net of transportation & storage at Edmonton	$ 30.20	$ 16.45	$ 27.24	$ 26.42
Total blend sales - bbls/d	22,275	13,189	58,015	93,479
% of total sales	24 %	14 %	62 %	100 %
	Edmonton (US$/bbl)		**USGC (US$/bbl)**	**USGC premium (US$/bbl)**
Average blend sales price by location	$ 26.56		$ 38.76	$ 12.20
Transportation and storage[1]	(3.84)		(13.88)	(10.04)
Transportation and storage from Christina Lake to Edmonton[2]	2.36		2.36	—
Blend sales price, net of transportation & storage at Edmonton	$ 25.08		$ 27.24	$ 2.16

(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$10.03 per barrel for the three months ended September 30, 2021 compared to C$18.55 per barrel for the three months ended September 30, 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 September 30, 2021 these activities contributed US$1.26 per barrel to the blend sales price at the USGC (pipeline) compared to US$0.88 per barrel 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 September 30, 2021 would be US$10.38 per barrel compared to US$11.64 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 September 30, 2020 would be US$13.00 per barrel compared to US$13.88 per barrel.

(4) Results are translated at the average foreign exchange rate of 1.2602 for the three months ended September 30, 2021 and 1.3316 for the three months ended September 30, 2020.

Blend sales distribution by sales market	**Nine months ended September 30, 2021**		
	Edmonton (US$/bbl)	**USGC (US$/bbl)**	
(US$ per barrel of blend sales, unless otherwise indicated)	**Pipeline**	**Pipeline**[3]	**TOTAL (US$/bbl)**
WTI - benchmark	$ 64.82	$ 64.82	$ 64.82
Differential - WTI:AWB at sales point	(15.14)	(4.01)	(10.67)
Asset optimization	—	1.27	0.51
Blend sales price	49.68	62.08	54.66
Transportation and storage[1]	(2.11)	(11.83)	(6.02)
Transportation and storage from Christina Lake to Edmonton[2]	2.11	2.11	2.11
Blend sales price, net of transportation & storage at Edmonton	$ 49.68	$ 52.36	$ 50.75
Total blend sales - bbls/d	76,892	51,524	128,416
% of total sales	60 %	40 %	100 %
	Edmonton (US$/bbl)	**USGC (US$/bbl)**	**USGC premium (US$/bbl)**
Average blend sales price by location	$ 49.68	$ 62.08	$ 12.40
Transportation and storage[1]	(2.11)	(11.83)	(9.72)
Transportation and storage from Christina Lake to Edmonton[2]	2.11	2.11	—
Blend sales price, net of transportation & storage at Edmonton	$ 49.68	$ 52.36	$ 2.68

Blend sales distribution by sales market	**Nine months ended September 30, 2020**			
	Edmonton (US$/bbl)		**USGC (US$/bbl)**	
(US$ per barrel of blend sales, unless otherwise indicated)	**Pipeline**	**Rail**	**Pipeline**[3][4]	**TOTAL (US$/bbl)**
WTI - benchmark	$ 38.32	$ 38.32	$ 38.32	$ 38.32
Differential - WTI:AWB at sales point	(19.34)	(17.32)	(4.22)	(13.46)
Asset optimization	—	—	1.34	0.50
Blend sales price	18.98	21.00	35.44	25.36
Transportation and storage[1]	(2.05)	(5.31)	(12.64)	(6.42)
Transportation and storage from Christina Lake to Edmonton[2]	2.05	2.05	2.05	2.05
Blend sales price, net of transportation & storage at Edmonton	$ 18.98	$ 17.74	$ 24.85	$ 20.99
Total blend sales - bbls/d	55,404	15,142	41,665	112,211
% of total sales	49 %	14 %	37 %	100 %
	Edmonton (US$/bbl)		**USGC (US$/bbl)**	**USGC premium (US$/bbl)**
Average blend sales price by location		$ 19.41	$ 35.44	$ 16.03
Transportation and storage[1]		(2.75)	(12.64)	(9.89)
Transportation and storage from Christina Lake to Edmonton[2]		2.05	2.05	—
Blend sales price, net of transportation & storage at Edmonton		$ 18.71	$ 24.85	$ 6.14

(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$10.76 per barrel for the nine months ended September 30, 2021 compared to C$12.44 per barrel for the nine months ended September 30, 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 nine months ended September 30, 2021 these activities contributed US$1.27 per barrel to the blend sales price at the USGC (pipeline) compared to US$1.34 per barrel 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 nine months ended September 30, 2021 would be US$10.56 per barrel compared to US$11.83 per barrel. If presented as a transportation and storage cost recovery, transportation and storage costs per barrel at the USGC (pipeline) during the nine months ended September 30, 2020 would be US$11.30 per barrel compared to US$12.64 per barrel.*

(4) *Includes 759 bbls/d of blend sales transported to the USGC via rail. USGC rail was suspended during the first quarter of 2020.*

(5) *Results are translated at the average foreign exchange rate of 1.2515 for the nine months ended September 30, 2021 and 1.3541 for the nine months ended September 30, 2020.*

On a transportation adjusted basis, the Corporation's USGC blend sales received a premium over the Edmonton blend sales of US$2.34 per barrel and US$2.68 per barrel for the three and nine months ended September 30, 2021. This compares to premiums of US$2.16 per barrel and US$6.14 per barrel at the USGC compared to the Edmonton market during the same periods of 2020. The higher premium during the three months ended September 30, 2021, compared to the same period of 2020, is primarily the result of wider realized differentials at Edmonton compared to the USGC and lower transportation costs, both resulting from higher apportionment on the Enbridge mainline system. The lower premium during the nine months ended September 30, 2021, compared to the same period of 2020, is primarily the result of narrower realized differentials at Edmonton due to improved pipeline egress capacity and increased storage capacity in Alberta, partially offset by reduced transportation costs in 2021 with the suspension of rail activity.

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 September 30		Nine months ended September 30	
($millions)	**2021**	**2020**	**2021**	**2020**
Sales from:				
Production	**$ 868**	$ 385	**$ 2,376**	$ 1,035
Purchased product[(1)]	**225**	140	**610**	437
Petroleum revenue	**$ 1,093**	$ 525	**$ 2,986**	$ 1,472
Royalties	**(23)**	(2)	**(44)**	(8)
Petroleum revenue, net of royalties	**$ 1,070**	$ 523	**$ 2,942**	$ 1,464
Power revenue	**$ 18**	$ 6	**$ 64**	$ 32
Transportation revenue	**3**	4	**8**	9
Other revenue	**$ 21**	$ 10	**$ 72**	$ 41
Total revenues	**$ 1,091**	$ 533	**$ 3,014**	$ 1,505

(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 and nine months ended September 30, 2021, total revenues approximately doubled from the same periods of 2020 primarily as a result of the increase in the average blend sales price which was mostly driven by the increase in WTI prices. The increase in total revenues was also impacted by a 36% and 14% increase in blend sales volumes, respectively.

Capital Expenditures

	Three months ended September 30		Nine months ended September 30	
($millions)	**2021**	2020(1)	**2021**	2020(1)
Sustaining and maintenance	**$ 79**	$ 21	**$ 203**	$ 70
Phase 2B brownfield expansion	**3**	—	**14**	14
Field infrastructure, corporate and other	**2**	—	**7**	—
Turnaround	**—**	15	**—**	25
eMVAPEX	**—**	2	**—**	8
	$ 84	$ 38	**$ 224**	$ 117
eMVAPEX government grant	**—**	(2)	**—**	(8)
	$ 84	$ 36	**$ 224**	$ 109

(1) Certain prior year costs have been reclassified for consistency with the Corporation's Phase 2B brownfield development plan.

The increase in capital spending for the three and nine months ended September 30, 2021, compared to the same periods 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.

The Corporation invested $84 million during the three months ended September 30, 2021 compared to $36 million during the same period of 2020. The majority of the $84 million invested in the quarter was directed towards sustaining and maintenance activities as well as incremental well capital necessary to allow the Corporation to fully utilize the Christina Lake central plant facility's oil processing capacity of approximately 100,000 bbls/d, prior to any impact from scheduled maintenance activity or outages. As previously disclosed in the Corporation's second quarter 2021 release, the total investment for this optimization initiative is approximately $125 million with $75 million included in the 2021 capital investment budget and the remainder expected to be invested in the first half of 2022.

The Corporation's eMVAPEX pilot has achieved most of its preliminary goals and is in the process of recovering previously injected solvent. The Corporation continues to evaluate the process.

The Phase 2B brownfield expansion is completed and the total cost of the expansion was approximately $260 million.

6. OUTLOOK

Based on better than expected production performance MEG is revising its full year 2021 average production to 92,500 – 93,500 bbls/d.

Summary of 2021 Guidance	Revised Guidance (November 8, 2021)	Revised Guidance (July 22, 2021)	Revised Guidance (May 3, 2021)	Original Guidance (December 7, 2020)
Bitumen production - annual average	92,500 - 93,500 bbls/d	91,000 - 93,000 bbls/d	88,000 - 90,000 bbls/d	86,000 - 90,000 bbls/d
Non-energy operating costs	$4.40 - $4.50 per bbl	$4.40 - $4.60 per bbl	$4.60 - $5.00 per bbl	$4.60 - $5.00 per bbl
G&A expense	$1.65 - $1.75 per bbl	$1.65 - $1.75 per bbl	$1.70 - $1.80 per bbl	$1.70 - $1.80 per bbl
Capital expenditures	$335 million	$335 million	$260 million	$260 million

The Corporation's estimate of full year 2021 total transportation costs range from US$6.00 to US$6.50 per barrel of AWB blend sales.

7. 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:

	Nine months ended September 30		2021			2020				2019
	2021	**2020**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
Average Benchmark Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**67.73**	42.55	**73.15**	68.98	61.06	45.25	43.39	33.30	50.95	62.50
WTI (US$/bbl)	**64.82**	38.32	**70.56**	66.07	57.84	42.66	40.93	27.85	46.17	56.96
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.51)**	(13.69)	**(13.58)**	(11.49)	(12.47)	(9.30)	(9.09)	(11.47)	(20.53)	(15.83)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(14.15)**	(15.56)	**(15.13)**	(13.11)	(14.22)	(10.56)	(10.48)	(13.44)	(22.78)	(18.44)
AWB – Edmonton (US$/bbl)	**50.67**	22.76	**55.43**	52.96	43.62	32.10	30.45	14.41	23.39	38.52
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(4.00)**	(5.41)	**(5.57)**	(3.92)	(2.52)	(2.83)	(3.20)	(7.29)	(5.74)	(5.25)
AWB – U.S. Gulf Coast (US$/bbl)	**60.82**	32.91	**64.99**	62.15	55.32	39.83	37.73	20.56	40.43	51.71
Condensate prices										
Condensate at Edmonton (C$/bbl)	**80.79**	47.51	**87.30**	81.55	73.51	55.39	50.03	30.72	61.76	70.01
Condensate at Edmonton as % of WTI	**99.6%**	91.6%	**98.2%**	100.5%	100.4%	99.6%	91.8%	79.6%	99.5%	93.1%
Condensate at Mont Belvieu, Texas (US$/bbl)	**61.79**	30.07	**68.19**	61.18	56.00	38.52	33.52	17.43	39.27	50.08
Condensate at Mont Belvieu, Texas as % of WTI	**95.3%**	78.5%	**96.6%**	92.6%	96.8%	90.3%	81.9%	62.6%	85.1%	87.9%
Natural gas prices										
AECO (C$/mcf)	**3.58**	2.32	**3.92**	3.37	3.43	2.88	2.48	2.21	2.26	2.70
Electric power prices										
Alberta power pool (C$/MWh)	**100.75**	46.69	**100.27**	104.73	97.25	46.05	43.75	29.94	66.38	47.07
Foreign exchange rates										
C$ equivalent of 1 US$ – average	**1.2515**	1.3541	**1.2602**	1.2280	1.2663	1.3031	1.3316	1.3860	1.3445	1.3201
C$ equivalent of 1 US$ – period end	**1.2750**	1.3324	**1.2750**	1.2405	1.2572	1.2755	1.3324	1.3616	1.4120	1.2965

The significant decline in global crude oil demand due to the effects of the COVID-19 pandemic impacted crude oil prices in 2020. Commodity prices have improved in 2021 in line with increased demand, optimism relating to vaccine rollouts and OPEC+ supply management.

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 and nine months ended September 30, 2021 compared to the same periods of 2020 due to market uncertainty surrounding possible gas supply constraints in 2021, coupled with extreme weather conditions in the first quarter of 2021.

Electric Power Prices

Electric power prices impact the price that the Corporation receives on the sale of surplus power from the Corporation's cogeneration facilities. The Alberta power pool price increased during the three and nine months ended September 30, 2021 compared to the same periods of 2020 primarily as a result of extreme weather conditions in February and June 2021 as well as in response to higher natural gas input costs.

8. OTHER OPERATING RESULTS

General and Administrative

	Three months ended September 30		Nine months ended September 30	
($millions, except as indicated)	**2021**	**2020**	**2021**	**2020**
General and administrative expense	**$ 14**	$ 10	**$ 41**	$ 35
General and administrative expense per barrel of production	**$ 1.72**	$ 1.50	**$ 1.68**	$ 1.61
Bitumen production – bbls/d	**91,506**	71,516	**91,386**	79,557

G&A expense increased 47% and 20% during the three and nine months ended September 30, 2021 compared to the same periods of 2020. In the second and third quarter of 2020, the Corporation benefited from 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. In response to this collapse, the Corporation took measures to reduce costs through salary rollbacks, reductions in staffing levels and vendor concessions. Many of the cost reductions that occurred in 2020 were temporary, and consistent with the improved price environment and increased production-related activities in 2021, costs have risen.

Depletion and Depreciation

	Three months ended September 30		Nine months ended September 30	
($millions, except as indicated)	**2021**	**2020**	**2021**	**2020**
Depletion and depreciation expense	**$ 108**	$ 87	**$ 324**	$ 304
Depletion and depreciation expense per barrel of production	**$ 12.78**	$ 13.33	**$ 12.97**	$ 13.97
Bitumen production – bbls/d	**91,506**	71,516	**91,386**	79,557

Total depletion and depreciation expense increased during the three and nine months ended September 30, 2021, compared to the same periods in 2020, primarily due to the increase in production. The depletion and depreciation expense per barrel decreased during the same periods as the depreciation expense of assets determined on a straight-line basis is spread over a greater number of barrels of production.

Exploration Expense

	Three months ended September 30		Nine months ended September 30	
($millions)	**2021**	**2020**	**2021**	**2020**
Exploration expense	**$ —**	$ —	**$ —**	$ 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 and nine months ended September 30, 2021 there was no exploration expense recognized. During the first quarter of 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 September 30		Nine months ended September 30	
($millions)	**2021**	**2020**	**2021**	**2020**
Realized:				
Crude oil contracts[1]	**$ (79)**	$ 15	**$ (254)**	$ 350
Condensate contracts[2]	**10**	(4)	**27**	(18)
Natural gas contracts[3]	**3**	—	**5**	—
Realized commodity risk management gain (loss)	**$ (66)**	$ 11	**$ (222)**	$ 332
Unrealized:				
Crude oil contracts[1]	**$ 65**	$ (36)	**$ (42)**	$ 81
Condensate contracts[2]	**(1)**	19	**(20)**	63
Natural gas contracts[3]	**4**	—	**15**	—
Unrealized commodity risk management gain (loss)	**$ 68**	$ (17)	**$ (47)**	$ 144
Commodity risk management gain (loss)	**$ 2**	$ (6)	**$ (269)**	$ 476

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

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

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

For the three months ended September 30, 2021, the Corporation recognized a $2 million net gain from commodity risk management primarily due to the gains on condensate and natural gas contracts, as the market prices of these commodities for current and future periods increased during the quarter, largely offset by losses on WTI fixed price contracts (including enhanced fixed price contracts with sold put options) as market WTI prices also increased.

For the nine months ended September 30, 2021, the Corporation recognized a $269 million net loss from commodity risk management primarily due to losses on WTI fixed price contracts (including enhanced fixed price contracts with sold put options) as market WTI prices for 2021 increased over the nine month period. These losses were partially offset by gains on natural gas and condensate contracts, as the market prices of these commodities for current and future periods increased.

During the three months ended September 30, 2020, the Corporation recognized a $6 million net loss from commodity risk management primarily reflecting a modest recovery in WTI prices through the third quarter of 2020. During the nine months ended September 30, 2020, the Corporation recognized a $476 million commodity risk management gain which reflected the significant decline in WTI prices due to the demand shock on global markets driven by COVID-19.

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 September 30		Nine months ended September 30	
(US$/bbl)	**2021**	**2020**	**2021**	**2020**
WTI fixed price contracts[1][2]:				
Average fixed price	**$ 46.18**	$ 44.51	**$ 46.77**	$ 53.47
Average settlement price	**70.55**	40.93	**62.98**	38.32
Gain (loss) on WTI fixed price contracts	**$ (24.37)**	$ 3.58	**$ (16.21)**	$ 15.15
WTI:WCS fixed differential contracts:				
Average fixed differential	**$ (11.05)**	$ (20.72)	**$ (12.13)**	$ (20.10)
Average settlement differential	**(13.46)**	(9.09)	**(11.88)**	(13.70)
Gain (loss) on WTI:WCS fixed differential contracts	**$ 2.41**	$ (11.63)	**$ (0.25)**	$ (6.40)
Condensate purchase contracts:				
Average fixed differential[3]	**$ (10.37)**	$ (5.15)	**$ (10.14)**	$ (5.44)
Average settlement differential	**(2.40)**	(7.41)	**(3.18)**	(8.26)
Gain (loss) on condensate purchase contracts	**$ 7.97**	$ (2.26)	**$ 6.96**	$ (2.82)
Natural gas purchase contracts:				
Average fixed price	**$ 2.60**	$ —	**$ 2.60**	$ —
Average settlement price	**3.41**	—	**3.09**	—
Gain (loss) on natural gas purchase contracts	**$ 0.81**	$ —	**$ 0.49**	$ —

(1) *Includes enhanced fixed price with sold put option contracts.*

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

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

Stock-based Compensation

	Three months ended September 30		Nine months ended September 30	
($millions)	**2021**	**2020**	**2021**	**2020**
Cash-settled expense (recovery)	**$ 13**	$ (1)	**$ 48**	$ (10)
Equity-settled expense	**4**	2	**12**	9
Equity price risk management (gain) loss[1]	**(7)**	9	**(44)**	(11)
Stock-based compensation	**$ 10**	$ 10	**$ 16**	$ (12)

(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 cash-settled expense recognized during the three and nine months ended September 30, 2021 was due to the increase in the Corporation's share price. The Corporation's common share price increased to $9.89 per share as at September 30, 2021 from its value of $8.97 per share as at June 30, 2021 and $4.45 per share as at December 31, 2020.

The cash-settled recovery during the three and nine months ended September 30, 2020 was due to the decrease in the Corporation's share price to $2.77 per share as at September 30, 2020 from its value of $3.77 per share as at June 30, 2020 and $7.39 per share as at December 31, 2019.

Equity-settled stock based compensation expense increased for the three and nine months ended September 30, 2021, compared to the same periods of 2020, primarily due to an increase in the value of awards granted which were temporarily reduced in 2020 in response to the challenging low oil price environment.

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 and nine months ended September 30, 2021, an equity price risk management gain of $7 million and $44 million, respectively, was recognized on the increase in share price during the periods.

Foreign Exchange Gain (Loss), Net

	Three months ended September 30		Nine months ended September 30	
($millions)	**2021**	**2020**	**2021**	**2020**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ (77)**	$ 67	**$ 9**	$ (95)
US$ denominated cash and cash equivalents	**(1)**	3	**(3)**	12
Unrealized net gain (loss) on foreign exchange	**(78)**	70	**6**	(83)
Realized gain (loss) on foreign exchange	**1**	—	**1**	(1)
Foreign exchange gain (loss), net	**$ (77)**	$ 70	**$ 7**	$ (84)

C$ equivalent of 1 US$				
Beginning of period	**1.2405**	1.3616	**1.2755**	1.2965
End of period	**1.2750**	1.3324	**1.2750**	1.3324

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.

During the three months ended September 30, 2021, the Canadian dollar weakened relative to the U.S. dollar by 3% resulting in an unrealized foreign exchange loss of $78 million. During the nine months ended September 30, 2021, the Canadian dollar strengthened slightly relative to the U.S. dollar resulting in an unrealized foreign exchange gain of $6 million.

During the three months ended September 30, 2020, the Canadian dollar strengthened by 2%, resulting in an unrealized foreign exchange gain of $70 million. During the nine months ended September 30, 2020, the Canadian dollar weakened relative to the U.S. dollar by 3%, resulting in an unrealized foreign exchange loss of $83 million.

Net Finance Expense

	Three months ended September 30		Nine months ended September 30	
($millions)	**2021**	**2020**	**2021**	**2020**
Interest expense on long-term debt	**$ 55**	$ 59	**$ 166**	$ 183
Interest expense on lease liabilities	**6**	6	**19**	19
Interest income	**(1)**	—	**(1)**	(2)
Net interest expense	**60**	65	**184**	200
Accretion on provisions	**2**	2	**6**	6
Debt extinguishment expense	**—**	—	**5**	—
Net finance expense	**$ 62**	$ 67	**$ 195**	$ 206
Average effective interest rate	**6.7%**	7.0%	**6.7%**	6.9%

Interest expense on long-term debt decreased during the three and nine months ended September 30, 2021 compared to the same periods of 2020 primarily as a result of the strengthening Canadian dollar as all of the Corporation's long-term debt is denominated in US dollars. Also contributing to the decrease was the refinancing of US$600 million of senior unsecured notes on February 2, 2021 at a rate of 5.875% compared to the previous rate of 7.0%.

For the nine months ended September 30, 2021, debt extinguishment expense was recognized in association with the August 23, 2021 debt redemption and included a cumulative debt redemption premium of $4 million and associated unamortized deferred debt issue costs of $1 million. Refer to Note 6 of the interim consolidated financial statements for further details.

Income Tax

	Three months ended September 30		Nine months ended September 30	
($millions)	**2021**	**2020**	**2021**	**2020**
Current income tax expense (recovery)	**$ —**	$ —	**$ (2)**	$ (1)
Deferred income tax expense (recovery)	**39**	(20)	**37**	(83)
Income tax expense (recovery)	**$ 39**	$ (20)	**$ 35**	$ (84)
Effective tax rate	**42 %**	78 %	**25 %**	19 %

For the three and nine months ended September 30, 2021, an income tax expense was recognized compared to an income tax recovery in the same periods of 2020 due to increased earnings before income taxes and foreign exchange gains and losses on long-term debt. Also, the Corporation recognized a $12 million deferred tax expense during the second quarter of 2021 associated with the tax treatment of a prior year investment in pipeline access. The Corporation disputes Canada Revenue Agency's assessment and continues to consider its alternatives.

As at September 30, 2021, the Corporation had approximately $7.3 billion of available Canadian tax pools and recognized a deferred income tax asset of $345 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

The effective tax rates differ from the Canadian statutory rate of 23% primarily due to the tax effect of foreign exchange gains and losses on the Corporation's long-term debt which is denominated in U.S. dollars.

9. LIQUIDITY AND CAPITAL RESOURCES

($millions)	September 30, 2021	December 31, 2020
Second Lien:		
6.5% senior secured second lien notes (Sept 30, 2021 - US$396 million; due 2025; December 31, 2020 - US$496 million)	**$ 505**	$ 633
Unsecured:		
7.125% senior unsecured notes (Sept 30, 2021 - US$1.2 billion; due 2027; December 31, 2020 - US$1.2 billion)	**1,530**	1,531
5.875% senior unsecured notes (Sept 30, 2021 - US$600 million; due 2029; December 31, 2020 - US$nil)	**765**	—
7.0% senior unsecured notes (Sept 30, 2021 - US$nil; December 31, 2020 - US$600 million; due 2024)	**—**	765
Debt redemption premium	**—**	9
Unamortized deferred debt discount and debt issue costs	**(31)**	(26)
Long-term debt	**2,769**	2,912
Cash and cash equivalents	**(210)**	(114)
Net debt(1)	**$ 2,559**	$ 2,798

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

On August 23, 2021, the Corporation redeemed US$100 million (approximately C$125 million) of the Corporation's 6.5% senior secured second lien notes due January 2025 at a redemption price of 103.25% plus accrued and unpaid interest.

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 $210 million as at September 30, 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 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 more than three years out, represented by US$396 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 September 30, 2021, the Corporation had $788 million of unutilized capacity under the $800 million revolving credit facility and the Corporation had $85 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 and $12 million remains outstanding as at September 30, 2021. 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 September 30		Nine months ended September 30	
($millions)	**2021**	**2020**	**2021**	**2020**
Net cash provided by (used in):				
Operating activities	**$ 257**	$ (31)	**$ 449**	$ 186
Investing activities	**(69)**	(36)	**(191)**	(145)
Financing activities	**(136)**	(6)	**(158)**	(209)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(1)**	2	**(4)**	11
Change in cash and cash equivalents	**$ 51**	$ (71)	**$ 96**	$ (157)

Cash Flow – Operating Activities

Net cash provided by operating activities for the three and nine months ended September 30, 2021 increased compared to the same periods of 2020, primarily due to higher benchmark crude oil prices.

Cash Flow – Investing Activities

Net cash used in investing activities increased during the three and nine months ended September 30, 2021 compared to the same periods of 2020 reflecting increased capital spending over these periods.

Cash Flow – Financing Activities

Net cash used in financing activities for the three months ended September 30, 2021 increased compared to the same period of 2020, primarily due to the debt redemption during the three months ended September 30, 2021.

Net cash used in financing activities for the nine months ended September 30, 2021 decreased compared to the same period of 2020, primarily due to larger debt repayment and associated higher debt redemption and refinancing costs incurred during the nine months ended September 30, 2020.

10. 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 September 30, 2021:

As at September 30, 2021			
Crude Oil Sales Contracts[1]	**Volumes (bbls/d)**[2]	**Term**	**Average Price (US$/bbl)**[2]
Enhanced Fixed Price with Sold Put Option			
WTI Fixed Price/Sold Put Option Strike Price	29,000	Oct 1, 2021 - Dec 31, 2021	$46.18 / $38.79
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	10,950	Oct 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	Oct 1, 2021 - Dec 31, 2021	$2.60
AECO Fixed Price	5,000	Jan 1, 2022 - Dec 31, 2023	$2.50

(1) *Incremental to these crude oil sales contracts, the Corporation occasionally enters into contracts to fix the spread between WTI prices for consecutive months to support certain marketing asset optimization activities. As at September 30, 2021, there were approximately 9,900 bbls/d and 3,300 bbls/d of these WTI hedges outstanding, which were scheduled to settle during October and November 2021, respectively. Unrealized losses on these totaled approximately $3.4 million.*

(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 September 30, 2021 and November 8, 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 September 30, 2021:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	$ (17)	$ 17
Condensate purchase price	± 5% in condensate price as a percentage of WTI	$ 5	$ 5
Natural gas purchase price	± C$0.50 per GJ applied to natural gas contracts	$ 4	$ (4)

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 September 30, 2021:

Condensate Purchase Contracts	**Volumes (bbls/d)(1)**	**Term**	**Average Price (US$/bbl)(1)**
WTI:Condensate Fixed Differential	3,078	Oct 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	Oct 1, 2021 - Dec 31, 2021	$2.70
Power Sales Contracts	**Quantity (MW)(1)**	**Term**	**Average Price (C$/MWh)(1)**
Fixed Price	35	Oct 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 and the revaluation is recognized in stock-based compensation expense. Net cash provided by (used in) operating activities is impacted when these stock-based compensation units are ultimately settled. The Corporation entered into these equity price risk management contracts to manage its exposure on cash-settled RSUs and PSUs vesting between 2021 and 2023.

	Three months ended September 30		**Nine months ended September 30**	
($millions)	**2021**	**2020**	**2021**	**2020**
Unrealized equity price risk management (gain) loss	**$ (7)**	$ 9	**$ (36)**	$ (11)
Realized equity price risk management (gain) loss	**—**	—	**(8)**	—
Equity price risk management (gain) loss	**$ (7)**	$ 9	**$ (44)**	$ (11)

11. SHARES OUTSTANDING

As at September 30, 2021, the Corporation had the following share capital instruments outstanding or exercisable:

(millions)	**Units**
Common shares	**306.8**
Convertible securities	
Stock options(1)	**2.6**
Equity-settled RSUs and PSUs	**6.6**

(1) 2.4 million stock options were exercisable as at September 30, 2021.

As at November 5, 2021, the Corporation had 306.8 million common shares, 2.5 million stock options and 6.6 million equity-settled RSUs and equity-settled PSUs outstanding, and 2.3 million stock options exercisable.

12. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations as at September 30, 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[(1)]	2022	2023	2024	2025	Thereafter	Total
Commitments:							
Transportation and storage[(2)]	$ 100	$ 405	$ 441	$ 441	$ 416	$ 5,677	$ 7,480
Diluent purchases	121	28	17	—	—	—	166
Other operating commitments	6	16	16	13	12	37	100
Variable office lease costs	1	4	4	4	4	27	44
Capital commitments	37	—	—	—	—	—	37
Total Commitments	265	453	478	458	432	5,741	7,827
Other Obligations:							
Lease obligations	19	43	38	37	29	491	657
Long-term debt[(3)]	—	—	—	—	505	2,295	2,800
Interest on long-term debt[(3)]	47	187	187	187	157	263	1,028
Decommissioning obligation[(4)]	—	4	5	4	4	778	795
Obligations	**$ 331**	**$ 687**	**$ 708**	**$ 686**	**$ 1,127**	**$ 9,568**	**$ 13,107**

(1) Amounts represent contractual maturities occurring in the fourth quarter of 2021.

(2) 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.

(3) 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 September 30, 2021.

(4) 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 was 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. During the third quarter of 2021, the Corporation reached an agreement to settle this litigation matter. Under the agreement, the Corporation paid (subsequent to the quarter) the sum of $21 million in full and final settlement of the claim and the claim has been discontinued.

13. 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.

14. 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.

15. RISK FACTORS

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

16. DISCLOSURE CONTROLS AND PROCEDURES

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

17. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

18. ABBREVIATIONS

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

Financial and Business Environment

AECO	Alberta natural gas price reference location
AIF	Annual Information Form
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

19. 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 2021 guidance, including full year 2021 production, non-energy operating costs, general and administrative costs, capital expenditures and total transportation costs; the Corporation's intention to continue debt reduction as a key component of its capital allocation strategy; 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 and reaching a 30% reduction in bitumen GHG emissions intensity (Scope 1 and Scope 2) from 2013 levels by 2030; the Oilsands Pathways to Net Zero Alliance working collectively with the federal and Alberta governments to achieve net zero GHG emissions from oil sands operations by 2050; the Corporation's expectation regarding the Christina Lake central plant facility's oil processing capacity of approximately 100,000 barrels per day and the amount of capital investment and the timing of such capital investment required to allow the Corporation to fully utilize this capacity; 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; commodity prices; estimates of reserves and resources; anticipated sources of funding for operations and capital expenditures; the Corporation's liquidity and ability to meet its current and future obligations; 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, transportation costs, foreign exchange rates and interest rates; the recoverability of the Corporation's reserves and contingent resources; the Corporation's ability to produce and market production of bitumen blend successfully to customers; future growth, results of operations and production levels; future capital and other expenditures; revenues, expenses and cash flow; operating costs; reliability; 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, including vaccine rollouts; actions taken by OPEC+ in relation to supply management; and business prospects and opportunities. By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated.

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

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

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

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

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

Estimates of Reserves and Resources

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

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.

20. ADDITIONAL INFORMATION

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

21. QUARTERLY SUMMARIES

	2021			2020				2019
Unaudited	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**
FINANCIAL *($millions unless specified)*								
Net earnings (loss)	**54**	68	(17)	16	(9)	(80)	(284)	26
Per share, diluted	**0.17**	0.22	(0.06)	0.05	(0.03)	(0.26)	(0.95)	0.09
Adjusted funds flow	**239**	166	127	84	26	89	76	156
Per share, diluted	**0.77**	0.53	0.41	0.27	0.09	0.29	0.25	0.51
Capital expenditures	**84**	70	70	40	36	20	54	72
Cash and cash equivalents	**210**	159	54	114	49	120	62	206
Working capital	**199**	127	8	55	131	173	371	123
Long-term debt	**2,769**	2,820	2,852	2,912	3,030	3,096	3,212	3,123
Shareholders' equity	**3,628**	3,564	3,491	3,506	3,495	3,507	3,593	3,853
BUSINESS ENVIRONMENT								
Average Benchmark Commodity Prices:								
WTI (US$/bbl)	**70.56**	66.07	57.84	42.66	40.93	27.85	46.17	56.96
Differential – WTI:WCS – Edmonton (US$/bbl)	**(13.58)**	(11.49)	(12.47)	(9.30)	(9.09)	(11.47)	(20.53)	(15.83)
Differential – WTI:AWB – Edmonton (US$/bbl)	**(15.13)**	(13.11)	(14.22)	(10.56)	(10.48)	(13.44)	(22.78)	(18.44)
AWB – Edmonton (US$/bbl)	**55.43**	52.96	43.62	32.10	30.45	14.41	23.39	38.52
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(5.57)**	(3.92)	(2.52)	(2.83)	(3.20)	(7.29)	(5.74)	(5.25)
AWB – U.S. Gulf Coast (US$/bbl)	**64.99**	62.15	55.32	39.83	37.73	20.56	40.43	51.71
C$ equivalent of 1US$ – average	**1.2602**	1.2280	1.2663	1.3031	1.3316	1.3860	1.3445	1.3201
Natural gas – AECO ($/mcf)	**3.92**	3.37	3.43	2.88	2.48	2.21	2.26	2.70
OPERATIONAL **($/bbl unless specified)**								
Blend sales, net of purchased product – bbls/d	127,546	129,474	128,236	136,623	93,479	100,980	142,380	134,932
Diluent usage – bbls/d	(35,295)	(39,494)	(40,938)	(40,892)	(25,910)	(30,583)	(45,166)	(40,585)
Bitumen sales – bbls/d	92,251	89,980	87,298	95,731	67,569	70,397	97,214	94,347
Bitumen production – bbls/d	**91,506**	91,803	90,842	91,030	71,516	75,687	91,557	94,566
Steam-oil ratio (SOR)	**2.56**	2.39	2.37	2.31	2.36	2.32	2.31	2.27
Blend sales	**74.54**	69.27	61.28	45.75	45.44	20.96	36.46	56.55
Cost of diluent	**(9.63)**	(9.18)	(8.94)	(7.11)	(5.76)	(10.78)	(17.01)	(9.69)
Bitumen realization	**64.91**	60.09	52.34	38.64	39.68	10.18	19.45	46.86
Transportation and storage – net	**(10.03)**	(10.91)	(11.41)	(14.11)	(18.55)	(11.77)	(8.63)	(10.75)
Third-party curtailment credits	**—**	—	—	0.03	—	—	0.18	(0.21)
Royalties	**(2.67)**	(1.71)	(0.85)	(0.23)	(0.21)	(0.05)	(0.63)	(1.18)
Non-energy operating costs	**(4.46)**	(3.84)	(4.05)	(4.70)	(3.96)	(4.09)	(4.57)	(4.49)
Energy operating costs	**(4.77)**	(4.27)	(4.34)	(3.73)	(3.17)	(3.00)	(3.15)	(2.95)
Power revenue	**2.06**	2.57	3.14	1.45	1.08	0.95	2.21	1.57
Realized gain (loss) on commodity risk management	**(7.73)**	(10.63)	(8.80)	1.31	1.71	33.62	11.97	(0.52)
Cash operating netback	**37.31**	31.30	26.03	18.66	16.58	25.84	16.83	28.33
Power sales price (C$/MWh)	**82.17**	88.40	93.27	46.34	39.03	28.34	69.39	49.61
Power sales (MW/h)	**101**	113	128	125	78	98	129	124
Average cost of diluent ($/bbl of diluent)	**99.69**	90.18	80.34	62.37	60.48	45.76	73.09	79.07
Average cost of diluent as a % of WTI	**112 %**	111 %	110 %	112 %	111 %	119 %	118 %	105 %
Depletion and depreciation rate per bbl of production	**12.78**	12.99	13.15	12.64	13.33	13.55	14.83	13.18
General and administrative expense per bbl of production	**1.72**	1.56	1.77	1.65	1.50	1.29	1.96	2.25
COMMON SHARES								
Shares outstanding, end of period (000)	**306,773**	306,716	303,137	302,681	302,657	302,645	299,547	299,508
Common share price ($) - close (end of period)	**9.89**	8.97	6.53	4.45	2.77	3.77	1.67	7.39

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$70.56/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 first half of 2021, 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;
- 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.

22. 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.*