Management's Discussion and Analysis | MEG ENERGY

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-month period ended March 31, 2019 was approved by the Corporation's Audit Committee on May 6, 2019. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three-month period ended March 31, 2019, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2018, the 2018 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 thousands of Canadian dollars, except where otherwise indicated.

MD&A - Table of Contents

1. BUSINESS DESCRIPTION

MEG is an oil sands company focused on sustainable *in situ* oil sands development and production in the southern Athabasca oil sands region of Alberta, Canada. MEG is actively developing enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods to improve the economic recovery of oil as well as lower carbon emissions. MEG is not engaged in oil sands mining. MEG transports and sells Access Western Blend ("AWB"or "blend") to refiners throughout North America and internationally.

MEG owns a 100% working interest in over 900 square miles of oil sands leases. In the GLJ Petroleum Consultants Ltd. Report ("GLJ Report"), effective December 31, 2018 with a preparation date of January 11, 2019, GLJ Petroleum Consultants Ltd. ("GLJ") estimated that the oil sands leases it had evaluated contained 2.8 billion barrels of proved plus probable bitumen reserves. For information regarding MEG's estimated reserves contained in the GLJ Report, please refer to the Corporation's most recently filed Annual Information Form ("AIF"), which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

The Corporation has identified three commercial SAGD projects; the Christina Lake Project, the Surmont Project and the May River Regional Project. The Christina Lake Project has received regulatory approval for 210,000 bbls/d of production, and is currently producing with a productive capacity of approximately 100,000 bbls/d. MEG has applied for regulatory approval for approximately 120,000 bbls/d of production at the Surmont Project and anticipates receiving regulatory approval in 2019. In 2017, MEG filed regulatory applications with the Alberta Energy Regulator for the May River Regional Project. Management anticipates, consistent with the estimates contained in the GLJ Report, that the May River Regional Project can support an average of 164,000 bbls/d of bitumen production.

The ultimate production rate and life of each project will be dependent on a number of factors, including the size, performance and development schedule for each expansion or phase in those projects. In addition, the Corporation holds other leases known as the "Growth Properties". The Growth Properties are in the resource definition and data gathering stage of development.

MEG has invested in three major projects at its Christina Lake Project, known as Phase 1, Phase 2 and Phase 2B. Phase 1 commenced production in 2008 with an initial bitumen production design capacity of approximately 3,000 bbls/d ("Phase 1"). Phase 2 commenced production in 2009 with an initial bitumen production design capacity of approximately 22,000 bbls/d and which utilized existing central processing facilities associated with Phase 1, and primarily expanded well pad drilling and tie-ins to increase production ("Phase 2"). Together, Phase 1 and Phase 2 had an initial bitumen production design capacity of approximately 25,000 bbls/d. Phase 2B commenced production in 2013 with an initial bitumen production design capacity of approximately 35,000 bbls/d ("Phase 2B"). The combined Phase 1, Phase 2 and Phase 2B initial bitumen production design capacity was approximately 60,000 bbls/d. Supported by proprietary reservoir technologies, MEG has been able to subsequently increase overall bitumen production in excess of 100,000 bbls/d through a series of low-cost debottlenecking and expansion projects and the redeployment of steam into new well pairs. 2018 bitumen production averaged 87,731 bbls/d. 2019 annual average production is expected to be in the range of 90,000 to 92,000 bbls/d, assuming the Alberta Government mandated production curtailment program remains in place for 2019 with easing over the course of the year. If curtailments were not in place, MEG would have the ability to produce an average of approximately 100,000 bbls/d of bitumen in 2019.

On March 22, 2018 the Corporation announced that it had successfully closed the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. The majority of the net cash proceeds were used to repay approximately C$1.2 billion of MEG's senior secured term loan. As part of the transaction, MEG entered into a Transportation Services Agreement ("TSA") dedicating MEG's Christina Lake production and condensate transport to Access Pipeline for an initial term of 30 years. The Access Pipeline is a dual pipeline system that connects the Christina Lake Project to a large regional upgrading, refining, diluent supply and transportation hub in the Edmonton, Alberta area.

The transaction also includes a Stonefell Lease Agreement which is a 30-year arrangement that secures MEG operational control and exclusive use of 100% of the Stonefell Terminal's 900,000 barrel blend and condensate storage facility. The Stonefell Terminal is connected to local and export markets by pipeline, in addition to being pipeline connected to the Bruderheim Terminal, a crude-by-rail loading facility near Edmonton, Alberta. This combination of facilities allows for the loading of bitumen blend for transport by rail.

MEG utilizes a network of pipeline, rail and storage facilities to optimize market access for the transport and sale of AWB to refiners throughout North America and internationally. MEG has contracted for 50,000 bbls/d (expanding to 100,000 bbls/d in mid-2020) of blend transportation capacity on the Flanagan South and Seaway pipeline systems, which provide pipeline access from Flanagan, Illinois through Cushing, Oklahoma to U.S. Gulf Coast refineries. MEG has incremental storage terminals in the U.S. Gulf Coast which, in addition to adding operational flexibility, also allow for loading ships for export internationally. In addition, MEG is a shipper on the Trans Mountain Expansion Project which, when in service, will provide MEG with 20,000 bbls/d of blend committed tidewater access to Canada's west coast. Also, effective January 1, 2019, MEG secured 30,000 bbls/d of blend unit train loading capacity at the Bruderheim Terminal for 3 years, with a 1-year extension option. The Corporation's marketing assets and flexibility are enhanced by exclusive use of the Stonefell Terminal. This combination of strategic marketing assets advances MEG's strategy of having long-term, broadening and reliable market access to world oil prices for its production.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

Adjusted funds flow in the first quarter of 2019 was $151 million, an increase of 82% from $83 million in the first quarter of 2018. This increase was primarily a result of both improved bitumen realization directly impacted by significantly tighter WTI:WCS differentials in the Edmonton market, and reduced diluent expense. This was partially offset by higher transportation expenses.

MEG's blend sales price averaged $59.02 per barrel in the first quarter of 2019 compared to $51.20 per barrel in the first quarter of 2018. Commencing January 1, 2019, the Government of Alberta enacted rules to limit the production of crude oil and bitumen. These provincially-mandated production curtailments for the industry had the effect of significantly narrowing the WTI:WCS differential at Edmonton during the first quarter of 2019, primarily contributing to the increase in blend sales price.

The Corporation's sales market strategy is also contributing to higher realized blend sales prices. The Corporation sold 31% of its sales volumes to the U.S. Gulf Coast market in the first quarter of 2019 compared to 25% in the same period of 2018. Net of transportation costs, barrels sold to the U.S. Gulf Coast market realized a $5 per barrel premium to those sold in the Edmonton market during the first quarter of 2019. A $16 per barrel premium was realized during the same period of 2018.

During the first quarter of 2019, the Corporation's bitumen realization averaged $50.21 per barrel compared to $35.46 per barrel in the first quarter of 2018. The significant narrowing of the WTI:WCS differential positively impacted the blend sales price. In addition, the Corporation's cost of diluent during the first quarter of 2019 was lower than the same period of 2018 due to lower average condensate pricing.

Bitumen production for the three months ended March 31, 2019 averaged 87,113 bbls/d compared to 93,207 bbls/d for the three months ended March 31, 2018. The decrease is primarily the result of the Alberta Government's mandated production curtailment program. If curtailments were not in place, the Corporation would have the ability to average approximately 100,000 bbls/d. Bitumen sales for the three months ended March 31, 2019 were 89,822 bbls/d compared to 91,608 bbls/d in the same period of 2018.

The Corporation recognized a net loss of $47.5 million in the first quarter of 2019 compared to net earnings of $140.6 million during the first quarter of 2018. The net loss recognized in the first quarter of 2019 included a $78.1 million net foreign exchange gain, a $12.3 million gain on the sale of earned Emission Performance Credits, and a $230.0 million loss on commodity risk management contracts, of which $209.0 million was unrealized. The net earnings recognized in the first quarter of 2018 primarily related to the $318.4 million gain recognized on the sale of the Corporation's 50% interest in the Access Pipeline, but also included a $107.9 million net foreign exchange loss, and a $75.8 million loss on commodity risk management contracts, of which $58.0 million was unrealized.

The Corporation is continuing its strategy of strengthening the balance sheet and improving its competitive position, driven by a focus on maximizing the Corporation's AWB sales price and improving overall cost efficiencies of the organization. To align with lower levels of capital spending and to further optimize operational efficiencies, staffing levels were reduced in the first quarter of 2019. In addition, MEG continues to progress the Board renewal process and will be announcing three new candidates this month, representing a broad range of skills and expertise, to stand for election at the Corporation's upcoming annual general meeting in June 2019.

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:

	2019	2018				2017		
($ millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Bitumen production - bbls/d	**87,113**	87,582	98,751	71,325	93,207	90,228	83,008	72,448
Bitumen sales - bbls/d	**89,822**	88,283	93,856	74,418	91,608	94,541	76,813	74,116
Bitumen realization - $/bbl	**50.21**	15.31	49.63	47.33	35.46	48.01	39.93	39.74
Net operating costs - $/bbl[1]	**6.17**	4.55	4.34	5.64	5.98	5.86	6.00	7.42
Non-energy operating costs - $/bbl	**5.22**	4.25	4.38	5.47	4.55	4.53	4.57	4.23
Cash operating netback - $/bbl[2]	**29.80**	7.14	24.01	18.66	20.31	33.54	26.88	23.04
Adjusted funds flow[3]	**151**	(38)	116	18	83	192	83	55
Per share, diluted[3]	**0.50**	(0.13)	0.39	0.06	0.28	0.65	0.28	0.19
Revenue[4]	**919**	520	803	689	721	755	576	584
Net earnings (loss)	**(48)**	(199)	118	(179)	141	(24)	84	104
Per share, basic	**(0.16)**	(0.67)	0.40	(0.61)	0.48	(0.08)	0.29	0.36
Per share, diluted	**(0.16)**	(0.67)	0.39	(0.61)	0.47	(0.08)	0.28	0.35
Total cash capital investment	**53**	144	145	183	148	163	103	158
Cash and cash equivalents	**154**	318	373	564	675	464	398	512
Long-term debt - C$	**3,660**	3,740	3,544	3,607	3,543	4,668	4,636	4,813
Long-term debt - US$	**2,740**	2,741	2,742	2,745	2,746	3,729	3,706	3,709

(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 is calculated by deducting the related diluent expense, transportation, net operating costs, royalties and realized commodity risk management gains (losses) from petroleum revenue, net of purchased product, on a per barrel of bitumen sales volume basis.

(3) Adjusted funds flow and the related per share amounts are non-GAAP measures and do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Adjusted funds flow is reconciled to net cash provided by (used in) operating activities and is discussed further under the heading "NON-GAAP MEASURES" in the "ADVISORY" section.

(4) The total of petroleum revenue, net of royalties and other revenue as presented on the consolidated statement of earnings and comprehensive income. Effective January 1, 2018, petroleum revenues are presented on a gross basis as they represent separate performance obligations, as discussed in the "NEW ACCOUNTING STANDARDS" section of this MD&A. The comparative prior period amounts have been revised to reflect the new presentation.

3. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended March 31	
	2019	**2018**
Bitumen production – bbls/d	**87,113**	93,207
Steam-oil ratio (SOR)	**2.2**	2.2

Bitumen Production

Bitumen production for the three months ended March 31, 2019 averaged 87,113 bbls/d compared to 93,207 bbls/d for the three months ended March 31, 2018. The 7% decrease in average production volumes for the three months ended March 31, 2019 was primarily due to the Alberta Government mandated production curtailment program which came into force January 1, 2019. The original announcement from the Alberta Government indicated that the curtailment restrictions are intended to terminate no later than December 31, 2019. Production curtailment limits are set on a monthly basis. If curtailments were not in place, the Corporation, through its patented eMSAGP technology at Christina Lake, would have the ability to produce an average of approximately 100,000 bbls/d of bitumen.

Steam-Oil Ratio

SOR is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The Corporation continues to focus on improving efficiency of production through a lower SOR. The SOR averaged 2.2 for the three months ended March 31, 2019 and March 31, 2018.

Operating Cash Flow

	Three months ended March 31	
($000)	**2019**	**2018**
Petroleum revenue, net of purchased product[1]	**$ 703,137**	$ 625,306
Diluent expense	**(297,250)**	(332,966)
	405,887	292,340
Royalties	**(2,995)**	(8,508)
Transportation[2]	**(91,144)**	(49,366)
Operating expenses	**(69,414)**	(59,230)
Power revenue	**19,514**	9,956
	261,848	185,192
Realized gain (loss) on commodity risk management	**(20,984)**	(17,719)
Operating cash flow[3]	**$ 240,864**	$ 167,473

(1) *Petroleum revenue, net of purchased product represents MEG's sales ("blend sales revenue") from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend") and net sales of third-party product for marketing-related activity. AWB is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.*

(2) *Defined as transportation expense less transportation revenue. Transportation includes costs associated with moving the Corporation's blend to a final sales location, net of third-party recoveries on diluent transportation arrangements.*

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

Operating cash flow was $240.9 million for the three months ended March 31, 2019 compared to $167.5 million for the three months ended March 31, 2018. Blend sales revenue increased by $77.8 million primarily due to a 15% increase in blend sales prices, partially offset by a 2% decrease in blend sales volumes. Blend sales prices were directly impacted by the narrowing of the WTI:WCS differential by 49% for the three months ended March 31, 2019 compared to the same period in 2018. Diluent expense for the three months ended March 31, 2019 was $35.7 million lower than the same period of 2018 due to lower condensate benchmark pricing and a decrease in condensate volumes, reflecting the decrease in diluent volumes required for blending. Offsetting the increase in blend sales revenue was a $41.8 million increase in transportation costs associated with a Transportation Service Agreement ("TSA") on Access Pipeline entered into on March 22, 2018, and increased blend volumes transported by rail.

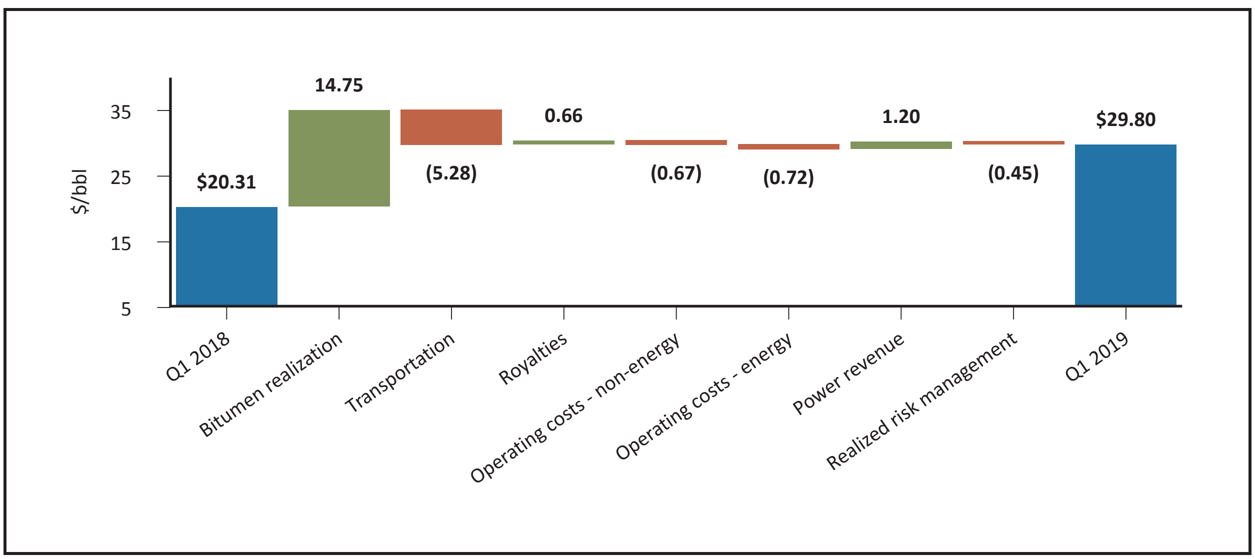
Cash Operating Netback

The following table summarizes the Corporation's per barrel calculation of operating cash flow, defined as cash operating netback, for the periods indicated:

	Three months ended March 31	
($ per barrel of bitumen sales)	**2019**	**2018**
Bitumen realization[1]	**$ 50.21**	$ 35.46
Transportation[2]	**(11.27)**	(5.99)
Royalties	**(0.37)**	(1.03)
	38.57	28.44
Operating costs – non-energy	**(5.22)**	(4.55)
Operating costs – energy	**(3.36)**	(2.64)
Power revenue	**2.41**	1.21
Net operating costs	**(6.17)**	(5.98)
Cash operating netback excluding realized commodity risk management	**32.40**	22.46
Realized gain (loss) on commodity risk management	**(2.60)**	(2.15)
Cash operating netback[3]	**$ 29.80**	$ 20.31
Bitumen sales - bbls/d	**89,822**	$ 91,608

(1) *Petroleum revenue, net of purchased product ("blend sales revenue"), less diluent expense.*
(2) *Defined as transportation expense less transportation revenue. Transportation includes costs associated with moving the Corporation's blend to a final sales location, net of third-party recoveries on diluent transportation arrangements.*
(3) *Cash operating netback and its components are on a per barrel of bitumen sales volume basis.*

Cash Operating Netback



Bitumen Realization

Bitumen realization represents the Corporation's petroleum revenue, net of purchased product ("blend sales revenue"), net of diluent expense, expressed on a per barrel of bitumen basis. Blend sales revenue represents MEG's revenue from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). AWB is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. The cost of blending is impacted by the amount of diluent required and the Corporation’s cost of purchasing and transporting diluent to the production site from both Edmonton and U.S. Gulf Coast markets. Diluent expense is also impacted by Canadian and U.S. benchmark pricing, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar. A portion of diluent expense is effectively recovered in the sales price of the blended product.

Bitumen realization averaged $50.21 per barrel for the three months ended March 31, 2019, compared to $35.46 per barrel for the three months ended March 31, 2018. The 42% increase quarter-over-quarter was due to an increase in the Corporation's realized blend sales price as a direct result of the significant narrowing of the WTI:WCS differential at Edmonton to US$12.29 per barrel for the three months ended March 31, 2019 from US$24.28 per barrel for the three months ended March 31, 2018. The benefit of the narrowing differential was partially offset by the lower WTI benchmark price in the first quarter of 2019 compared to the same period in 2018. To increase overall bitumen realization, approximately 31% of blend sales volumes were delivered to the U.S. Gulf Coast in the first quarter of 2019 compared to 25% in the same period of 2018. U.S. Gulf Coast pricing is typically sold at a premium to the Edmonton, Alberta market. Refer to the Marketing Activity section of this MD&A for further details.

Also improving bitumen realization was a decrease to the Corporation's average cost of diluent during the first quarter of 2019 to $77.61 per barrel of diluent for the three months ended March 31, 2019 from $83.91 per barrel of diluent for the three months ended March 31, 2018. This was primarily due to a decrease in average condensate benchmark pricing.

Transportation

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

In March 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. As part of the transaction, MEG entered into a Transportation Service Agreement ("TSA") dedicating MEG’s Christina Lake production and condensate transport to the Access Pipeline for an initial term of 30 years.

During the three months ended March 31, 2019, transportation costs averaged $11.27 per barrel compared to $5.99 per barrel for the three months ended March 31, 2018. The increase in costs on a per barrel basis is the result of incremental transportation costs associated with the TSA and additional costs associated with increased blend volumes transported by rail.

Royalties

The Corporation's royalty expense is based on price-sensitive royalty rates set by the Government of Alberta. The applicable royalty rates change depending on whether a project is pre-payout or post-payout, with payout being defined as the point in time when a project has generated enough cumulative net revenues to recover its cumulative costs. The royalty rate applicable to pre-payout oil sands operations 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. All of the Corporation's projects are currently pre-payout.

Royalties averaged $0.37 per barrel for the three months ended March 31, 2019, compared to $1.03 per barrel for the three months ended March 31, 2018. The decrease in royalties per barrel is primarily the result of lower WTI crude oil prices, plus a $0.31 per barrel recovery related to prior year royalty adjustments.

Net Operating Costs

Net operating costs are comprised of the sum of non-energy operating costs and energy operating costs, reduced by power revenue. Net operating costs for the three months ended March 31, 2019 averaged $6.17 per barrel compared to $5.98 per barrel for the three months ended March 31, 2018. The increase in net operating costs is primarily the result of an increase in both non-energy and energy operating costs, partially offset by an increase in power revenue.

Non-energy operating costs relate to production-related operating activities. Non-energy operating costs averaged $5.22 per barrel for the three months ended March 31, 2019, compared to $4.55 for the three months ended March 31, 2018. The increase in non-energy operating costs per barrel is primarily due to a higher portion of staff and service costs ascribed to operations, primarily as a result of lower levels of capital spending, combined with lower sales volumes for the three months ended March 31, 2019 compared to the same period in 2018.

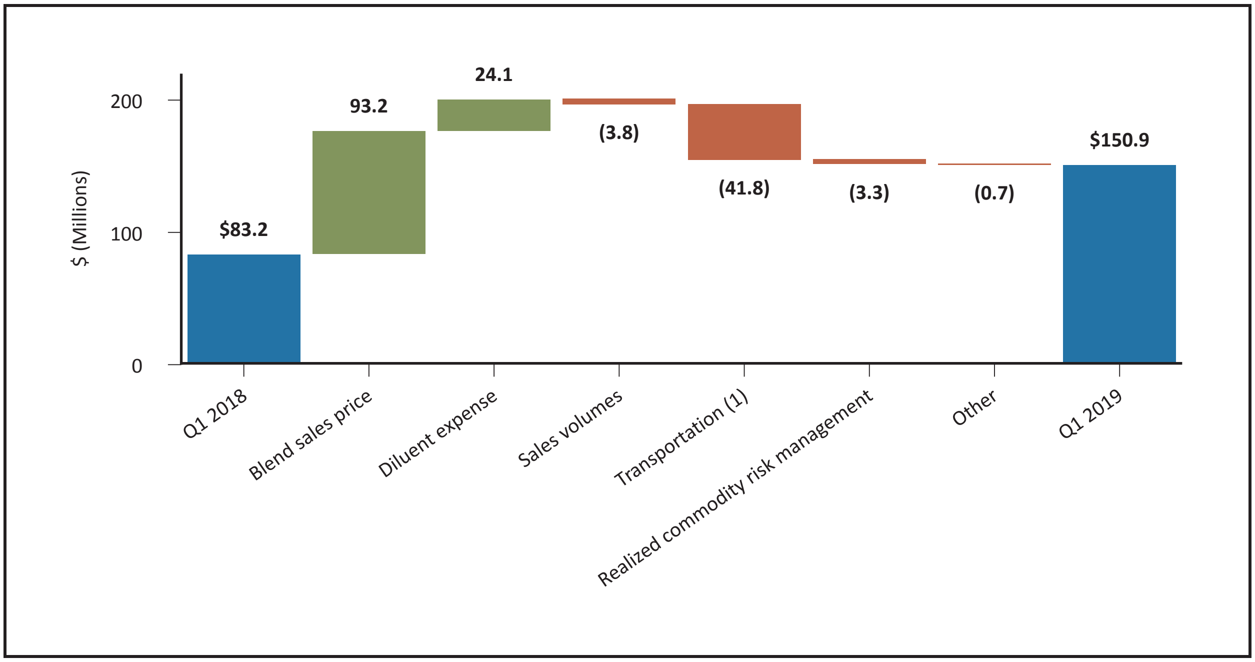
Energy operating costs reflect the cost of natural gas used for fuel to generate steam and power at the Corporation's facilities. Energy operating costs averaged $3.36 per barrel for the three months ended March 31, 2019 compared to $2.64 per barrel for the three months ended March 31, 2018. The increase in energy operating costs is primarily attributable to higher natural gas prices. The Corporation's natural gas purchase price averaged $3.03 per mcf during the three months ended March 31, 2019 compared to $2.40 per mcf in the same period of 2018.

Power revenue is recognized from the sale of surplus power generated by the Corporation's cogeneration facilities at the Christina Lake Project. MEG utilizes cogeneration facilities to provide a portion of its steam requirements and to reduce its overall carbon footprint as excess power is sold into the provincial power grid. Power revenue averaged $2.41 per barrel for the three months ended March 31, 2019 compared to $1.21 per barrel for the three months ended March 31, 2018. The Corporation's average realized power sales price during the three months ended March 31, 2019 was $70.83 per megawatt hour compared to $35.50 per megawatt hour in 2018. The higher average realized price is attributable to the retirement and suspension of older coal-fired power plants and extreme cold weather in the province of Alberta.

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. The realized loss on commodity risk management averaged $2.60 per barrel for the three months ended March 31, 2019 compared to a realized loss of $2.15 per barrel for the three months ended March 31, 2018. This is primarily due to the settlement of losses on commodity risk management contracts relating to crude oil sales. Refer to the commodity risk management discussion within the "OTHER OPERATING RESULTS" section of this MD&A for further details.

Adjusted Funds Flow



(1) *Defined as transportation expense less transportation revenue.*

Adjusted funds flow is a non-GAAP measure, as defined in the "NON-GAAP MEASURES" section of this MD&A, which is used by the Corporation to analyze operating performance and liquidity. Adjusted funds flow increased by 82% in the first quarter of 2019 to $150.9 million from $83.2 million in the first quarter of 2018. The increase in adjusted funds flow was primarily the result of narrowing differentials that increased the AWB realized price, and a decrease in diluent expense. These items were partially offset by higher transportation expense.

Marketing Activity

MEG utilizes a network of pipelines, rail and storage facilities to optimize market access to transport and sell Access Western Blend ("AWB" or "blend") to refiners throughout North America and beyond. AWB is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. The Corporation's network of storage, pipeline and rail commitments helps to mitigate the impact of apportionment on the Enbridge Mainline system and provides significantly higher and less volatile pricing through market diversification. MEG is well-positioned to access the premium U.S. Gulf Coast market, where a shortfall in heavy crude supply is expected over the medium term. MEG has contracted for 50,000 bbls/d (expanding to 100,000 bbls/d in mid-2020) of blend transportation capacity on the Flanagan South and Seaway pipeline systems, which provide pipeline access from Flanagan, Illinois through Cushing, Oklahoma to U.S. Gulf Coast refineries. Also, effective January 1, 2019, MEG secured unit train loading capacity at the Bruderheim terminal for 3 years, with a 1-year extension option. Rail will continue to be an important lever in MEG's marketing strategy to mitigate Edmonton pricing exposure and to reach premium markets. This combination of strategic marketing assets advances MEG's strategy of having long-term, broadening and reliable market access to world oil prices for its production.

The following table summarizes the Corporation’s blend sales, net of transportation by sales market for the periods noted to assist in understanding the Corporation's marketing portfolio. Per barrel figures presented below are based on blend sales volumes:

	Three months ended March 31, 2019					
	Edmonton (US$/bbl)		U.S. Gulf Coast (US$/bbl)			
	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)	TOTAL (C$/bbl)
WTI	$ 54.90	$ 54.90	$ 54.90	$ 54.90	$ 54.90	$ 72.98
Differential - WTI:WCS	(12.29)	(12.29)	(0.05)	(0.05)	(8.45)	(11.23)
Differential - WCS:AWB and other	(3.35)	1.47	0.28	(2.92)	(2.05)	(2.72)
Blend sales price	39.26	44.08	55.13	51.93	44.40	59.02
Transportation[1]	(1.94)	(4.57)	(10.92)	(23.32)	(5.75)	(7.65)
Blend sales price, net of transportation	$ 37.32	$ 39.51	$ 44.21	$ 28.61	$ 38.65	$ 51.37

	Edmonton (US$/bbl)	U.S. Gulf Coast (US$/bbl)	U.S. Gulf Coast premium (US$/bbl)	U.S. Gulf Coast premium (C$/bbl)
Average blend sales price by location	$ 39.80	$ 54.46	$ 14.66	$ 19.49
Transportation[1]	(2.23)	(13.47)	(11.24)	(14.94)
Blend sales price, net of transportation	$ 37.57	$ 40.99	$ 3.42	$ 4.55

	Pipeline	Rail	Pipeline	Rail	TOTAL
Total blend sales - bbls/d	80,754	10,099	32,974	8,550	132,377
% of total sales	61%	8%	25%	6%	100%

[1] *Defined as transportation expense less transportation revenue, per barrel of blend sales volumes, and includes the per barrel cost of transportation from Christina Lake to Edmonton. Transportation per barrel based on bitumen sales volumes was C$11.27 per barrel for the three months ended March 31, 2019.*

	Three months ended March 31, 2018					
	Edmonton (US$/bbl)		U.S. Gulf Coast (US$/bbl)			
	Pipeline	Rail	Pipeline	Rail	TOTAL (US$/bbl)	TOTAL (C$/bbl)
WTI	$ 62.87	$ 62.87	$ 62.87	—	$ 62.87	$ 79.54
Differential - WTI:WCS	(24.28)	(24.28)	(4.52)	—	(19.28)	(24.39)
Differential - WCS:AWB and other	(3.68)	0.76	(2.07)	—	(3.12)	(3.95)
Blend sales price	34.91	39.35	56.28	—	40.47	51.20
Transportation[1]	(0.77)	(8.40)	(9.31)	—	(3.19)	(4.04)
Blend sales price, net of transportation	$ 34.14	$ 30.95	$ 46.97	—	$ 37.28	$ 47.16

	Edmonton (US$/bbl)	U.S. Gulf Coast (US$/bbl)	U.S. Gulf Coast premium (US$/bbl)	U.S. Gulf Coast premium (C$/bbl)
Average blend sales price by location	$ 35.11	$ 56.28	$ 21.17	$ 26.78
Transportation[1]	(1.12)	(9.31)	(8.19)	(10.36)
Blend sales price, net of transportation	$ 33.99	$ 46.97	$ 12.98	$ 16.42

	Pipeline	Rail	Pipeline	Rail	TOTAL
Total blend sales - bbls/d	96,678	4,684	34,339	—	135,701
% of total sales	71%	4%	25%	—	100%

[1] *Defined as transportation expense less transportation revenue, per barrel of blend sales volumes, and includes the per barrel cost of transportation from Christina Lake to Edmonton. Transportation per barrel based on bitumen sales volumes was C$5.99 for the three months ended March 31, 2018.*

Blend sales for the three months ended March 31, 2019 averaged 132,377 bbls/d compared to 135,701 bbls/d for the three months ended March 31, 2018. During the first quarter of 2019, the Corporation's sales volumes transported by rail averaged 18,649 bbls/d, 46% of which were delivered to the U.S. Gulf Coast, compared to 4,684 bbls/d of total sales volumes transported by rail for the same period in 2018. For the three months ended March 31, 2019, transportation costs per barrel for blend volumes transported by rail destined for the U.S. Gulf Coast were impacted by fixed costs associated with the Corporation's currently underutilized capacity at the Bruderheim terminal, as well as one-time costs associated with the change out of the Corporation's leased rail car fleet.

The blend sales price, net of transportation had an approximate $5 per barrel price uplift at the U.S. Gulf Coast compared to Edmonton for the three months ended March 31, 2019. This compares to an approximate $16 per barrel price uplift at the U.S. Gulf Coast compared to Edmonton for the same period in 2018. The per-barrel price uplift is due to the Corporation's secured access to the U.S. Gulf Coast, where sales pricing is not subject to the same heavy oil differential as the Edmonton, Alberta market. The price uplift in the three months ended March 31, 2019 was lower than the same period of 2018 due to the tighter WTI:WCS differential at Edmonton.

Revenue

Revenue represents the total of petroleum revenue, net of royalties and other revenue. Revenue for the three months ended March 31, 2019 totaled $918.6 million compared to $720.6 million for the three months ended March 31, 2018. Revenue increased as a result of the increase in the average blend sales price, partially offset by lower blend sales volumes, as well as higher third-party sales volumes.

Net Earnings (Loss)

The Corporation recognized a net loss of $47.5 million for the three months ended March 31, 2019 compared to net earnings of $140.6 million for the three months ended March 31, 2018. The net loss for the three months ended March 31, 2019 included a gain on asset disposition of $12.3 million, related to the sale of earned Emission Performance Credits, compared to a gain on asset dispositions of $318.4 million in the same period of 2018, related to the sale of the Corporation's 50% interest in the Access Pipeline. The net loss for the three months ended March 31, 2019 included a net foreign exchange gain of $78.1 million compared to a net foreign exchange loss of $107.9 million for the three months ended March 31, 2018. The net loss for the three months ended March 31, 2019 also included a loss on commodity risk management contracts of $230.0 million, of which $209.0 million was unrealized, compared to a loss on commodity risk management contracts of $75.8 million, of which $58.0 million was unrealized, for the same period in 2018.

Net capital investment

	Three months ended March 31	
($000)	**2019**	**2018**
Sustaining and maintenance	$ **19,930**	$ 52,488
Phase 2B brownfield expansion	**16,262**	17,810
Field infrastructure, corporate and other	**10,408**	6,437
eMVAPEX	**6,693**	24,261
eMSAGP	**—**	46,743
Total cash capital investment	**53,293**	147,739
Capitalized cash-settled stock-based compensation	**(409)**	(125)
	$ **52,884**	$ 147,614

Total cash capital investment for the three months ended March 31, 2019 was $53.3 million, compared to $147.7 million for the three months ended March 31, 2018. The decrease in capital spending reflects MEG's disciplined 2019 capital budget of $200 million. Capital investment in the period was primarily directed towards sustaining and maintenance activities as well as completing work already underway on the Phase 2B Brownfield expansion.

4. OUTLOOK

Summary of 2019 Guidance	Guidance January 22, 2019
Total cash capital investment	$200 million
Bitumen production – annual average (bbls/d)	90,000 – 92,000
Non-energy operating costs ($/bbl)	$4.75 – $5.25
General and administrative expense ($/bbl)	$1.95 – $2.05

On January 22, 2019, the Corporation announced a 2019 capital budget of $200 million. MEG's 2019 capital program will direct $115 million towards sustaining and maintenance capital and $40 million towards growth capital directed at the ongoing Phase 2B brownfield expansion and the advancement of the eMVAPEX pilot program. The remaining $45 million will be directed towards field infrastructure, corporate and other initiatives.

The Corporation's primary focus is applying free cash flow to its debt balance. A potential discretionary capital budget addition of $75 million will be reviewed mid-2019, and is subject to market conditions. Additional capital would be directed to MEG's Phase 2B brownfield expansion, which, when completed, would increase production to 113,000 bbls/d. The Phase 2B expansion capital budget of $275 million is approximately 65% complete.

The Corporation's 2019 annual bitumen production volumes are targeted to be in the range of 90,000 - 92,000 bbls/d. Non-energy operating costs are targeted to be in the range of $4.75 - $5.25 per barrel. MEG's operational guidance assumes the Alberta Government mandated production curtailment program remains in place for 2019, but eases over the course of the year. Should the temporary curtailment be lifted, MEG could rapidly return production to 100,000 bbls/d, with non-energy operating costs in the range of $4.40 - $4.90 per barrel.

To align with lower levels of capital spending and to further optimize operational efficiencies, the Corporation reduced its staffing levels in February 2019. Based on the current production guidance, MEG anticipates 2019 general and administrative expense of $1.95 - $2.05 per barrel.

Based on results to date and expectations for the remainder of the year, the Corporation's guidance remains unchanged.

5. BUSINESS ENVIRONMENT

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

	2019	2018				2017		
	Q1	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Average Commodity Prices								
Crude oil prices								
Brent (US$/bbl)	**63.90**	68.08	75.97	74.90	67.18	61.54	52.18	50.93
WTI (US$/bbl)	**54.90**	58.81	69.50	67.88	62.87	55.40	48.21	48.29
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.29)**	(39.43)	(22.25)	(19.27)	(24.28)	(12.26)	(9.94)	(11.13)
Differential – WCS:AWB – Edmonton (US$/bbl)	**(2.21)**	(5.17)	(3.44)	(2.94)	(3.17)	(2.30)	(1.89)	(2.00)
AWB – Edmonton (US$/bbl)	**40.40**	14.21	43.81	45.67	35.42	40.84	36.38	35.16
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(0.89)**	(6.25)	(5.63)	(7.83)	(7.00)	(5.48)	(6.61)	(7.93)
AWB – U.S. Gulf Coast (US$/bbl)	**54.01**	52.56	63.87	60.05	55.87	49.92	41.60	40.36
Condensate prices								
Condensate at Edmonton (C$/bbl)	**67.25**	59.63	87.35	88.84	79.72	73.72	59.59	65.16
Condensate at Edmonton as % of WTI	**92.1%**	76.7%	96.2%	101.4%	100.2%	104.6%	98.7%	100.3%
Condensate at Mont Belvieu, Texas (US$/bbl)	**48.31**	51.21	64.53	64.40	59.27	55.35	46.37	44.77
Condensate at Mont Belvieu, Texas as % of WTI	**88.0%**	87.1%	92.8%	94.9%	94.3%	99.9%	96.2%	92.7%
Natural gas prices								
AECO (C$/mcf)	**2.86**	1.70	1.28	1.26	2.26	1.84	1.58	2.81
Electric power prices								
Alberta power pool (C$/MWh)	**70.73**	55.57	54.46	55.92	34.81	22.49	24.55	19.26
Foreign exchange rates								
C$ equivalent of 1 US$ – average	**1.3293**	1.3215	1.3070	1.2911	1.2651	1.2717	1.2524	1.3449
C$ equivalent of 1 US$ – period end	**1.3360**	1.3646	1.2924	1.3142	1.2901	1.2518	1.2510	1.2977

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. The WTI price averaged US$54.90 per barrel for the three months ended March 31, 2019 compared to US$62.87 per barrel for the three months ended March 31, 2018.

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 North American heavy oil prices at Hardisty, Alberta. The WTI:WCS differential at Edmonton averaged US$12.29 per barrel, for the three months ended March 31, 2019 compared to US$24.28 per barrel for the three months ended March 31, 2018. The Corporation sells AWB, a heavy oil similar to WCS, but generally priced at a discount to the WCS benchmark at Edmonton, with the discount dependent on both the quality differential to WCS and the supply/demand fundamentals for heavy crude oil in Western Canada. AWB is also sold at the U.S. Gulf Coast, along with other U.S. Gulf Coast heavy crude oils and is sold at a discount or premium to WTI dependent on the supply/demand fundamentals for heavy crude oil in the U.S. Gulf Coast region.

On December 3, 2018 the Government of Alberta enacted rules to enable a temporary curtailment of crude oil and bitumen production (the "Curtailment Rules"). The Curtailment Rules came into force on January 1, 2019 and are intended to terminate no later than December 31, 2019. The Curtailment Rules give the Province the authority to make an order to set the maximum combined provincial production amount of crude oil and bitumen on a monthly basis. As a result, the WTI:WCS differential significantly narrowed for the three months ended March 31, 2019 compared to the fourth quarter of 2018.

Condensate Prices

In order to facilitate pipeline transportation of bitumen, MEG uses condensate sourced at both Edmonton and the U.S. Gulf Coast as diluent for blending with the Corporation’s bitumen. The Corporation's committed diluent purchases at the U.S. Gulf Coast reference benchmark pricing at Mont Belvieu, Texas.

Condensate prices, benchmarked at Edmonton, averaged $67.25 per barrel, or 92.1% of WTI, for the three months ended March 31, 2019 compared to $79.72 per barrel, or 100.2% of WTI, for the three months ended March 31, 2018. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$48.31 per barrel, or 88.0% of WTI, for the three months ended March 31, 2019 compared to US$59.27 per barrel, or 94.3% of WTI, for the three months ended March 31, 2018. Condensate sourced from Mont Belvieu, Texas is subject to transportation costs from Mont Belvieu to the Edmonton area.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, as it is used as fuel to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facilities. The AECO natural gas price averaged $2.86 per mcf for the three months ended March 31, 2019 compared to $2.26 per mcf for the three months ended March 31, 2018. The AECO natural gas price has increased as a result of unseasonably cold weather, partially offset by continued pipeline constraints and lack of demand growth.

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 averaged $70.73 per megawatt hour for the three months ended March 31, 2019 compared to $34.81 per megawatt hour for the three months ended March 31, 2018. Alberta power pool prices have increased due to the retirement and suspension of older coal-fired power plants and extreme cold weather in the province of Alberta.

Foreign Exchange Rates

Changes in the value of the Canadian dollar relative to the U.S. dollar have an impact on the Corporation's blend sales revenue and diluent expense, as blend sales prices and diluent expense are determined by reference to U.S. benchmarks. Changes in the value of the Canadian dollar relative to the U.S. dollar also have an impact on principal and interest payments on the Corporation's U.S. dollar denominated debt. A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on blend sales revenue and a negative impact on diluent expense and principal and interest payments. Conversely, an increase in the value of the Canadian dollar has a negative impact on blend sales revenue and a positive impact on diluent expense and principal and interest payments.

The Corporation recognizes net unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents at each reporting date. As at March 31, 2019, the Canadian dollar, at a rate of 1.3360 per U.S. dollar, had increased in value by approximately 2% against the U.S. dollar compared to its value as at December 31, 2018, when the rate was 1.3646.

6. OTHER OPERATING RESULTS

Depletion and Depreciation

	Three months ended March 31	
($000)	2019	2018
Depletion and depreciation expense	$ 115,107	$ 110,899
Depletion and depreciation expense per barrel of production	$ 14.68	$ 13.22

Depletion and depreciation expense per barrel increased for the three months ended March 31, 2019 compared to the three months ended March 31, 2018, primarily due to lower bitumen production volumes and an increase in depreciable costs, partially offset by a decrease in future development costs associated with the Corporation's depletable assets.

Commodity Risk Management Gain (Loss)

The Corporation has entered into financial commodity risk management contracts to increase the predictability of the Corporation's cash flow by managing commodity price volatility. The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes. All financial commodity risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss). Realized gains or losses on financial commodity risk management contracts are the result of contract settlements during the period. Unrealized gains or losses on financial commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.

	Three months ended March 31					
($000)	2019			2018		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude oil contracts[1]	$ (18,302)	$ (202,354)	$ (220,656)	$ (17,719)	$ (58,419)	$ (76,138)
Condensate contracts[2]	(2,682)	(6,642)	(9,324)	—	387	387
Commodity risk management gain (loss)	$ (20,984)	$ (208,996)	$ (229,980)	$ (17,719)	$ (58,032)	$ (75,751)

(1) *Includes WTI fixed price, WTI collars and WTI:WCS fixed differential contracts.*

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

The Corporation realized a net loss on commodity risk management contracts of $21.0 million for the three months ended March 31, 2019, primarily due to net settlement losses on crude oil contracts. This compares to a realized net loss of $17.7 million for the three months ended March 31, 2018. WTI:WCS fixed differential contracts, which fixed the differential at approximately US$23 per barrel, settled, on average, at approximately US$12 per barrel. Condensate contracts, which fixed the price of condensate at 92% of WTI, settled, on average, at approximately 90% of WTI. The realized losses from the settlement of these contracts were partially offset by gains on WTI fixed price contracts, which fixed prices at approximately US$67 per barrel, and settled, on average, at approximately US$55 per barrel.

The Corporation recognized an unrealized net loss on commodity risk management contracts of $209.0 million for the three months ended March 31, 2019, reflecting unrealized losses on both crude oil and condensate contracts. The $202.4 million unrealized loss on crude oil contracts reflects increasing crude oil benchmark forward prices, resulting in unrealized losses on the Corporation's WTI fixed price contracts, combined with narrowing WTI:WCS forward differentials resulting in unrealized losses on WTI:WCS fixed differential contracts. In addition, forward prices for condensate decreased relative to WTI, resulting in a $6.6 million unrealized loss on the Corporation's condensate contracts. The $209.0 million unrealized loss for the three months ended March 31, 2019 compares to a $58.0 million unrealized loss in the same period of 2018. Refer to the "Risk Management" section of this MD&A for further details.

General and Administrative

	Three months ended March 31	
($000)	2019	2018
General and administrative expense	$ 17,767	$ 21,723
General and administrative expense per barrel of production	$ 2.27	$ 2.59

General and administrative expense per barrel decreased 12% for the three months ended March 31, 2019 to $2.27 per barrel, from $2.59 per barrel for the three months ended March 31, 2018. The per barrel decrease was primarily due to the reduction of general and administrative staffing levels in February 2019 to align with lower levels of capital spending and to further optimize operational efficiencies. Based on the current production guidance, and as the full impact of the staff cost reduction is captured, MEG anticipates 2019 general and administrative expense to average $1.95 - $2.05 per barrel.

Stock-based Compensation

	Three months ended March 31	
($000)	2019	2018
Cash-settled expense (recovery)	$ (9,438)	$ (291)
Equity-settled expense	4,294	6,129
Stock-based compensation	$ (5,144)	$ 5,838

Stock-based compensation recovery for the three months ended March 31, 2019 was $5.1 million compared to stock-based compensation expense of $5.8 million for the three months ended March 31, 2018. The recovery in 2019 was primarily the result of a decrease in the fair value of the cash-settled units due to a decrease in the Corporation's common share price. As at March 31, 2019, the Corporation's common share price decreased by approximately 34% compared to its value on December 31, 2018.

Foreign Exchange Gain (Loss), Net

	Three months ended March 31	
($000)	2019	2018
Unrealized foreign exchange gain (loss) on:		
Long-term debt	$ 79,285	(138,784)
Other	(2,267)	(2,514)
Unrealized net gain (loss) on foreign exchange	77,018	(141,298)
Realized gain (loss) on foreign exchange	1,080	(2,010)
Realized gain (loss) on foreign exchange derivatives	—	35,362
Foreign exchange gain (loss), net	$ 78,098	$ (107,946)

C$ equivalent of 1 US$		
Beginning of period	1.3646	1.2518
End of period	1.3360	1.2901

Net foreign exchange gains and losses are primarily due to the translation of U.S. dollar denominated debt as a result of the strengthening or weakening of the Canadian dollar compared to the U.S. dollar during each period. For the three months ended March 31, 2019, the Canadian dollar strengthened by 2%, resulting in an unrealized foreign exchange gain on translation of U.S. dollar denominated debt of $79.3 million. For the three months ended March 31, 2018, the Canadian dollar weakened by 3%, resulting in an unrealized foreign exchange loss on translation of U.S. dollar denominated debt of $138.8 million.

In March 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. Upon entering into the sale agreement, the Corporation entered into forward currency contracts to manage the foreign exchange risk on the Canadian dollar denominated sale proceeds designated for U.S. dollar denominated long-term debt repayment. The Corporation settled these forward currency contracts on closing of the sale and realized a foreign exchange gain of $35.4 million.

Net Finance Expense

	Three months ended March 31	
($000)	**2019**	**2018**
Interest expense on long-term debt	**$ 71,724**	$ 82,865
Interest expense on lease liabilities	**6,503**	441
Interest income	**(1,325)**	(2,181)
Net interest expense	**76,902**	81,125
Accretion on provisions	**1,665**	1,910
Unrealized loss (gain) on derivative financial liabilities[1]	**(253)**	2,976
Realized loss (gain) on interest rate swaps	**—**	(17,312)
Net finance expense	**$ 78,314**	$ 68,699
Average effective interest rate[2]	**6.6%**	6.2%

(1) *Derivative financial liabilities include the 1% interest rate floor and the interest rate swap that was settled in March 2018.*
(2) *Defined as the weighted average interest rate applied to the U.S. dollar denominated senior secured term loan, senior secured second lien notes, and senior unsecured notes outstanding, including the impact of the interest rate swap.*

Interest expense on long-term debt for the three months ended March 31, 2019 was $71.7 million compared to $82.9 million for the three months ended March 31, 2018. The interest expense decrease for the three months ended March 31, 2019 was primarily due to the repayment of approximately C$1.2 billion of the Corporation's senior secured term loan in the first quarter of 2018 from a portion of the proceeds from the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. As a result of the repayment, the Corporation terminated its existing interest rate swap contract, which effectively fixed the interest rate on a portion of its senior secured term loan, and realized a gain of $17.3 million for the three months ended March 31, 2018.

Other Expenses

	Three months ended March 31	
($000)	**2019**	**2018**
Severance and other	**$ 6,983**	$ 187
Onerous contracts expense	**—**	644
Other expenses	**$ 6,983**	$ 831

The Corporation recognized other expenses of $7.0 million for the three months ended March 31, 2019 compared to $0.8 million for the three months ended March 31, 2018. The increase was due to severance costs related to the Corporation reducing its staffing levels to align with a lower level of capital spending and improve overall cost efficiencies.

Income Tax Expense (Recovery)

	Three months ended March 31	
($000)	**2019**	**2018**
Current income tax expense	**$ 243**	$ 116
Deferred income tax expense (recovery)	**(45,669)**	(29,774)
Income tax expense (recovery)	**$ (45,426)**	$ (29,658)

The Corporation recognizes current income taxes associated with its operations in the United States. The Corporation's Canadian operations are not currently taxable. As at March 31, 2019, the Corporation had approximately $7.6 billion of available Canadian tax pools.

The Corporation recognized a current income tax expense of $0.2 million for the three months ended March 31, 2019 and a current income tax expense of $0.1 million for the three months ended March 31, 2018, related to its operations in the United States.

The Corporation recognized a deferred income tax recovery of $45.7 million for the three months ended March 31, 2019 and a deferred income tax recovery of $29.8 million for the three months ended March 31, 2018.

The Corporation's effective tax rate on earnings is impacted by permanent differences. The significant permanent differences are:

- The permanent difference due to the non-taxable portion of realized and unrealized foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the three months ended March 31, 2019, the non-taxable gain was $39.6 million compared to a non-taxable loss of $69.4 million for the three months ended March 31, 2018.

- Non-taxable stock-based compensation expense for equity-settled plans is a permanent difference. Stock-based compensation expense for equity-settled plans for the three months ended March 31, 2019 was $4.3 million compared to $6.1 million for the three months ended March 31, 2018.

As at March 31, 2019, the Corporation recognized a deferred income tax asset of $277.8 million. Estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

As at March 31, 2019, the Corporation had not recognized the tax benefit related to $396.0 million of realized and unrealized taxable foreign exchange losses.

7. LIQUIDITY AND CAPITAL RESOURCES

($000)	**March 31, 2019**	**December 31, 2018**
Cash and cash equivalents	**$ 154,080**	$ 317,704
Senior secured term loan (March 31, 2019 – US$222.3 million; due 2023; December 31, 2018 – US$225.4 million)	**296,993**	307,552
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,068,800**	1,091,640
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,336,000**	1,364,550
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**1,002,000**	1,023,413
US$1.4 billion revolving credit facility (due 2021)	**—**	—
Total debt(1)(2)	**$ 3,703,793**	$ 3,787,155

(1) The non-GAAP measure of total debt is reconciled to long-term debt in accordance with IFRS under the heading "NON-GAAP MEASURES" and discussed further in the "ADVISORY" section.

(2) On February 14, 2019, S&P Global Ratings ("S&P") lowered the Corporation's long-term issuer credit rating to B+ from BB- and lowered the issue-level rating on the Corporation's senior secured term loan, senior secured second lien notes and revolving credit facility to BB from BB+. S&P also changed the ratings outlook to negative. The Corporation's senior secured term loan, senior secured second lien notes and revolving credit facility do not include any provision that would require any changes in payment schedules or terminations as a result of the lower credit rating.

Capital Resources

The Corporation's cash and cash equivalents balance was $154.1 million as at March 31, 2019 compared to $317.7 million as at December 31, 2018. As at March 31, 2019, no amount had been drawn under the Corporation’s US$1.4 billion revolving credit facility.

All of the Corporation's long-term debt is denominated in U.S. dollars. Total debt decreased by C$0.1 billion to C$3.7 billion as at March 31, 2019 from C$3.8 billion as at December 31, 2018, primarily as a result of the increase in value of the Canadian dollar relative to the U.S. dollar.

The Corporation’s letter of credit facility, guaranteed by Export Development Canada, has a limit of US$440 million. Letters of credit under this facility do not consume capacity of the revolving credit facility. As at March 31, 2019, the Corporation had US$165.2 million of unutilized capacity under this facility.

The senior secured term loan, revolving credit facility, letter of credit facility and second lien notes are secured by substantially all the assets of the Corporation. All of MEG’s long-term debt, the revolving credit facility and the letter of credit facility are “covenant-lite” in structure, meaning they are free of any financial maintenance covenants and are not dependent on, nor calculated from, the Corporation’s crude oil reserves. The first maturity of any of the Corporation’s outstanding long-term debt obligations is in 2023.

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.

The objectives of the Corporation's investment guidelines for surplus cash are to ensure preservation of capital and to maintain adequate liquidity to meet the Corporation’s cash flow requirements. The Corporation only places surplus cash investments with counterparties that have a short term credit rating of R-1 (high) or equivalent. The Corporation has experienced no material loss or lack of access to its cash in operating accounts, invested cash or cash equivalents. However, the Corporation can provide no assurance that access to its invested cash and cash equivalents will not be impacted by adverse conditions in the financial markets. While the Corporation monitors the cash balances in its operating and investment accounts according to its investment practices and adjusts the cash balances as appropriate, these cash balances could be impacted if the underlying financial institutions or corporations fail or are subject to other adverse conditions in the financial markets.

Risk Management

Commodity Price Risk Management

Fluctuations in market conditions and commodity prices can impact the Corporation’s financial performance, operating results, cash flows, expansion and growth opportunities, access to funding and the cost of borrowing. Under the Corporation’s strategic commodity risk management program, derivative financial instruments are employed to increase the predictability of the Corporation's cash flow, by managing commodity price volatility. MEG’s commodity risk management program is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes.

To mitigate the Corporation’s exposure to fluctuations in crude oil prices, the Corporation periodically enters into financial commodity risk management contracts to partially manage its exposure on blend sales and condensate purchases.

The Corporation had the following financial commodity risk management contracts relating to crude oil sales and condensate purchases outstanding as at March 31, 2019:

As at March 31, 2019	Volumes (bbls/d)[(1)]	Term	Average Price (US$/bbl)[(1)]
Crude Oil Sales Contracts			
WTI Fixed Price	34,446	Apr 1, 2019 - Dec 31, 2019	$63.97
WTI:WCS Fixed Differential	51,608	Apr 1, 2019 - Dec 31, 2019	$(21.49)
WTI:WCS Fixed Differential	17,000	Jan 1, 2020 - Dec 31, 2020	$(22.18)
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	5,168	Apr 1, 2019 - Dec 31, 2019	$(7.56)
WTI:Mont Belvieu Fixed Differential	6,000	Jan 1, 2020 - Dec 31, 2020	$(7.62)
Mont Belvieu Fixed % of WTI	9,750	Apr 1, 2019 - Dec 31, 2019	92.2 %
Mont Belvieu Fixed % of WTI	7,750	Jan 1, 2020 - Dec 31, 2020	93.1 %

The Corporation entered into the following commodity risk management contracts relating to crude oil sales and condensate purchases between April 1, 2019 and May 3, 2019:

Subsequent to March 31, 2019	Volumes (bbls/d)[(1)]	Term	Average Prices (US$/bbl)[(1)]
Crude Oil Sales Contracts			
WTI Fixed Price	2,957	Apr 1, 2019 - Apr 30, 2019	$62.50
WTI Fixed Price	15,179	May 1, 2019 - May 31, 2019	$63.46
WTI Fixed Price	2,280	Jul 1, 2019 - Dec 31, 2019	$61.43
WTI Fixed Price	15,000	Jan 1, 2020 - Dec 31, 2020	$59.37
WTI:WCS Fixed Differential	3,300	Jul 1, 2019 - Dec 31, 2019	$(17.89)
Condensate Purchase Contracts			
WTI:Mont Belvieu Fixed Differential	1,250	Jan 1, 2020 - Dec 31, 2020	$(7.67)

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

Interest Rate Risk Management

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix. In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate at approximately 5.3% on US$650 million of its US$1.2 billion senior secured term loan. In the first quarter of 2018, the Corporation completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. A majority of the net cash proceeds were used to repay approximately C$1.2 billion of the Corporation's senior secured term loan. As a result, the Corporation terminated its interest rate swap contract and realized a gain of $17.3 million for the three months ended March 31, 2018. The Corporation did not have any outstanding interest rate swap contracts as at March 31, 2019 and March 31, 2018.

Cash Flow Summary

	Three months ended March 31	
($000)	2019	2018
Net cash provided by (used in):		
Operating activities	**$ (69,729)**	$ 118,026
Investing activities	**(83,638)**	1,368,002
Financing activities	**(7,551)**	(1,272,775)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(2,706)**	(1,668)
Change in cash and cash equivalents	**$ (163,624)**	$ 211,585

Cash Flow – Operating Activities

Net cash used in operating activities totaled $69.7 million for the three months ended March 31, 2019 compared to net cash provided by operating actives of $118.0 million for the three months ended March 31, 2018. Net cash used in operating activities for the first quarter of 2019 included a significant decrease in non-cash working capital of $220.3 million, primarily due to the settlement of December 2018 revenues when benchmark crude oil prices were significantly lower. This was partially offset by a higher bitumen realization in March 2019.

Cash Flow – Investing Activities

Net cash used in investing activities was $83.6 million for the three months ended March 31, 2019 compared to net cash provided by investing activities of $1.4 billion for the three months ended March 31, 2018. The three months ended March 31, 2019 included the receipt of cash proceeds of $12.5 million, primarily related to the sale of earned Emission Performance Credits, which compares to cash proceeds of $1.5 billion from the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal that closed in the first quarter of 2018.

Cash Flow – Financing Activities

Net cash used in financing activities was $7.6 million for the three months ended March 31, 2019 compared to net cash used in financing activities of $1.3 billion for the three months ended March 31, 2018. Net cash used in financing activities for the three months ended March 31, 2019 included a quarterly debt repayments of US$3.1 million. Net cash used in financing activities for the three months ended March 31, 2018 consisted of a $1.3 billion partial repayment of the Corporation's senior secured term loan from the majority of the net cash proceeds from the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal.

8. SHARES OUTSTANDING

As at March 31, 2019, the Corporation had the following share capital instruments outstanding or exercisable:

(000)	Units
Common shares	**296,857**
Convertible securities	
Stock options[1]	**8,412**
Equity-settled RSUs and PSUs	**6,151**

(1) 6.6 million stock options were exercisable as at March 31, 2019.

As at May 3, 2019, the Corporation had 296.9 million common shares, 8.4 million stock options and 6.1 million equity-settled restricted share units and equity-settled performance share units outstanding, and 6.6 million stock options exercisable.

9. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations as at March 31, 2019. 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.

($000)	2019	2020	2021	2022	2023	Thereafter	Total
Transportation and storage[1]	$ 262,562	$ 380,592	$ 421,041	$ 426,320	$ 443,820	$ 6,284,126	$ 8,218,461
Long-term debt[2]	12,375	16,500	16,500	16,500	1,303,918	2,338,000	3,703,793
Interest on long-term debt[2]	186,089	243,075	242,109	241,144	176,635	93,938	1,182,990
Decommissioning obligation[3]	1,695	3,592	5,485	5,485	5,485	703,694	725,436
Diluent purchases	325,631	21,153	21,095	21,095	17,570	—	406,544
Office lease rentals	17,747	21,879	21,614	20,778	18,160	135,544	235,722
Other commitments[4]	13,979	12,568	10,472	9,441	9,452	50,123	106,035
Total	**$ 820,078**	**$ 699,359**	**$ 738,316**	**$ 740,763**	**$ 1,975,040**	**$ 9,605,425**	**$ 14,578,981**

(1) *This represents transportation and storage commitments from 2019 to 2048.*

(2) *This represents the scheduled principal repayments of the senior secured term loan, the senior secured second lien notes, the senior unsecured notes, and associated interest payments based on interest and foreign exchange rates in effect on March 31, 2019.*

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

(4) *This represents the future commitments associated with the Corporation's capital program, and other operating and maintenance commitments.*

Contingencies

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

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

10. NON-GAAP MEASURES

Certain financial measures in this MD&A including: funds flow from (used in) operations, adjusted funds flow, operating cash flow, cash operating netback and total debt are non-GAAP measures. These terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Funds Flow From (Used in) Operations and Adjusted Funds Flow

Funds flow from (used in) operations and adjusted funds flow are non-GAAP measures utilized by the Corporation to analyze operating performance and liquidity. Funds flow from (used in) operations excludes the net change in non-cash operating working capital while the IFRS measurement "net cash provided by (used in) operating activities" includes these items. Adjusted funds flow excludes the net change in non-cash operating working capital, realized gain on foreign exchange derivatives not considered part of ordinary continuing operating results, payments on onerous contracts and decommissioning expenditures, while the IFRS measurement "net cash provided by (used in) operating activities" includes these items. Funds flow from (used in) operations and adjusted funds flow are not intended to represent net cash provided by (used in) operating activities calculated in accordance with IFRS. Funds flow from (used in) operations and adjusted funds flow are reconciled to net cash provided by (used in) operating activities in the table below.

	Three months ended March 31	
($000)	**2019**	**2018**
Net cash provided by (used in) operating activities	**$ (69,729)**	$ 118,026
Net change in non-cash operating working capital items	**220,287**	(8,136)
Funds flow from (used in) operations	**150,558**	109,890
Adjustments:		
Realized gain on foreign exchange derivatives[1]	**—**	(35,362)
Payments on onerous contracts	**—**	6,008
Decommissioning expenditures	**340**	2,621
Adjusted funds flow	**$ 150,898**	$ 83,157

(1) A gain related to the settlement of forward currency contracts to manage the foreign exchange risk on Canadian dollar denominated proceeds related to the sale of assets designated for U.S. dollar denominated long-term debt repayment.

Operating Cash Flow and Cash Operating Netback

Operating cash flow is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to fund future capital investments. The Corporation's operating cash flow is calculated by deducting the related diluent expense, blend purchases, transportation, operating expenses, royalties and realized commodity risk management gains or losses from proprietary blend sales revenue and power revenue. The per-unit calculation of operating cash flow, defined as cash operating netback, is calculated by deducting the related diluent expense, blend purchases, transportation, operating expenses, royalties and realized commodity risk management gains or losses from proprietary blend revenue and power revenue, on a per barrel of bitumen sales volume basis.

Total Debt

Total debt is a non-GAAP measure which is used by the Corporation to analyze leverage and liquidity. The Corporation's total debt is defined as long-term debt as reported, the current portion of the senior secured term loan, the unamortized financial derivative liability discount, and the unamortized deferred debt discount and debt issue costs. Total debt is reconciled to long-term debt in the table below.

($000)	March 31, 2019	December 31, 2018
Long-term debt	$ **3,659,547**	$ 3,740,150
Adjustments:		
Current portion of senior secured term loan	**16,500**	16,852
Unamortized financial derivative liability discount	**—**	1,267
Unamortized deferred debt discount and debt issue costs	**27,746**	28,886
Total debt	$ **3,703,793**	$ 3,787,155

11. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting 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.

For a detailed discussion regarding the Corporation's critical accounting policies and estimates, please refer to the Corporations 2018 annual MD&A. Additional estimates, assumptions and judgments are detailed in the Corporation's unaudited interim consolidated financial statements.

12. NEW ACCOUNTING STANDARDS

IFRS 16 *Leases*

The IASB issued IFRS 16, *Leases* ("IFRS 16"), which replaces IAS 17 *Leases*, and is effective for annual periods beginning on or after January 1, 2019. IFRS 16, a single recognition and measurement model applicable to lessees, requires recognition of lease assets and lease liabilities on the balance sheet. The standard eliminates the classification of leases as either operating leases or finance leases for lessees, essentially treating all leases as finance leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases. The accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases.

The Corporation adopted IFRS 16 *Leases,* effective January 1, 2019, using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period comparative financial information as the cumulative effect is recognized as an adjustment to the opening deficit on the transition date and the standard is applied prospectively. Therefore, the comparative information in the Corporation's condensed Consolidated balance sheet, Consolidated statement of earnings (loss) and comprehensive income, Consolidated statement of changes in shareholders' equity, and Consolidated statement of cash flow have not been restated.

On adoption of IFRS 16, the Corporation elected to use the following practical expedients permitted by the standard:

- Applied a single discount rate to a portfolio of leases with similar characteristics;
- Accounted for leases with a remaining term of less than 12 months as at January 1, 2019 as short-term leases;
- Used hindsight when determining the lease term where the contract contained options to extend or terminate the lease;
- Excluded initial direct costs from the measurement of the right-of-use ("ROU") asset as at January 1, 2019; and

Relied on the Corporation's previous assessment of whether leases were onerous under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* immediately before initial application as an alternative to performing an impairment review on the ROU assets. ROU assets have been adjusted by the amount of the onerous contracts provision recognized in the consolidated financial statements as at December 31, 2018.

The impacts of the adoption of IFRS 16, as at January 1, 2019, are as follows:

		IFRS 16 Opening Balance Sheet Adjustments			
	Reported balance as at Dec 31, 2018	Finance Sublease Receivables[(a)]	Transportation Leases[(b)]	Office Leases[(b)]	Restated balance as at January 1, 2019
Assets					
Property, plant and equipment	$ 6,645,224		$ 17,418	$ 41,607	$ 6,704,249
Other assets	210,628	19,164			229,792
Deferred income tax asset	236,578	(5,174)		773	232,177
Liabilities					
Provisions and other liabilities	(293,817)		(17,418)	(44,469)	(355,704)
Shareholders' Equity					
Deficit	1,750,653	(13,990)		2,089	1,738,752
	$ 8,549,266	**$ —**	**$ —**	**$ —**	**$ 8,549,266**

a. On adoption, the Corporation has recognized finance sublease receivables in relation to certain sublease arrangements that were previously recognized on the consolidated balance sheet as at December 31, 2018 within the onerous contracts provision.

b. On adoption, the Corporation has recognized lease liabilities in relation to lease arrangements measured at the present value of the remaining lease payments as at December 31, 2018, and discounted using the Corporation's estimated incremental borrowing rate as of January 1, 2019. The associated right-of-use assets were measured at the amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, on January 1, 2019.

Significant Accounting Policies

Leases

The Corporation has applied IFRS 16 using the modified retrospective approach. As a result, the comparative information contained herein has been accounted for in accordance with the Corporation's previous accounting policies which can be found in the audited consolidated financial statements for the year ended December 31, 2018.

The following accounting policy is applicable as of January 1, 2019:

The Corporation assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration.

As Lessee

Leases are recognized as a lease liability and a corresponding ROU asset at the date on which the leased asset is available for use by the Corporation. Liabilities and assets arising from a lease are initially measured on a present value basis. Lease liabilities are measured at the present value of the remaining lease payments, discounted using the Corporation's estimated incremental borrowing rate when the rate implicit in the lease is not readily available. The corresponding right-of-use assets are measured at the amount equal to the lease liability.

The lease liability is measured at amortized cost using the effective interest method. It is remeasured when there is a change in the future lease payments arising from a change in an index or rate, if there is a change in the amount expected to be payable under a residual value guarantee or if there is a change in the assessment of whether the Corporation will exercise a purchase, extension or termination option that is within the control of the Corporation.

The ROU asset, initially measured at an amount equal to the corresponding lease liability, is depreciated on a straight-line basis, over the shorter of the estimated useful life of the asset or the lease term. The ROU asset may be adjusted for certain remeasurements of the lease liability and impairment losses.

Upon adoption of IFRS 16, there is an increase to depletion and depreciation expense on right-of-use assets, an increase to net finance expense on lease liabilities, a reduction to general and administrative expense and a reduction to transportation expense. Accounting treatment of existing sale and leasebacks resulting in a finance lease under IAS 17 remain unchanged.

Lease payments are allocated between the lease liability and finance costs. Cash outflows for repayment of the principal portion of the lease liability is classified as cash flows from financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

Leases that have terms of less than twelve months or leases on which the underlying asset is of low value are recognized as an expense in the consolidated statement of earnings (loss) on a straight-line basis over the lease term.

As Lessor

Accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, and disclosure requirements are enhanced. As an intermediate lessor, the Corporation accounts for its interest in the head lease and subleases separately. The Corporation has reassessed subleases previously classified as operating leases under IAS 17 to determine whether each sublease should be classified as an operating lease or a finance lease. An operating lease that is reclassified to a finance lease is accounted for as a new finance lease entered into on January 1, 2019.

13. RISK FACTORS

The Corporation's primary focus is on the ongoing development and operation of its oil sands assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including construction risks, operations risks, project development risks and political-economic risks. Further information regarding the risk factors which may affect the Corporation is contained in the most recently filed Annual Information Form, which is available on the Corporation’s website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

14. DISCLOSURE CONTROLS AND PROCEDURES

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

15. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

16. ABBREVIATIONS

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

Financial and Business Environment

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
GAAP	Generally Accepted Accounting Principles
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

17. ADVISORY

Forward-Looking Information

This document may contain forward-looking information including but not limited to: expectations of future production, revenues, expenses, cash flow, operating costs, steam-oil ratios, pricing differentials, reliability, profitability and capital investments; estimates of reserves and resources; anticipated reductions in operating costs as a result of optimization and scalability of certain operations; anticipated sources of funding for operations and capital investments; and anticipated regulatory approvals. 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.

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 include, but are not limited to: risks associated with the oil and gas industry, for example, results securing access to markets and transportation infrastructure and the commitments and risks therein; extent and timelines of the Alberta Government's mandatory production curtailment program; outlook for regulatory approval timelines for the Surmont Project; availability of capacity on the electricity transmission grid; uncertainty of reserve and resource estimates; uncertainty associated with estimates and projections relating to production, costs and revenues; health, safety and environmental risks; risks of legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws; assumptions regarding and the volatility of commodity prices, interest rates and foreign exchange rates, and, risks and uncertainties related to commodity price, interest rate and foreign exchange rate swap contracts and/or derivative financial instruments that MEG may enter into from time to time to manage its risk related to such prices and rates; risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with MEG's future phases and the expansion and/or operation of MEG's projects; risks and uncertainties related to the timing of completion, commissioning, and start-up, of MEG's future phases, expansions and projects; the operational risks and delays in the development, exploration, production, and the capacities and performance associated with MEG's projects; and uncertainties arising in connection with any future disposition of assets.

Although MEG 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 MEG's most recently filed Annual Information Form ("AIF"), along with MEG's other public disclosure documents. Copies of the AIF and MEG's other public disclosure documents are available through the SEDAR website which is available 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 MEG 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 focused on sustainable in situ oil sands development and production in the southern Athabasca oil sands region of Alberta, Canada. MEG is actively developing enhanced oil recovery projects that utilize SAGD extraction methods. MEG's common shares are listed on the Toronto Stock Exchange under the symbol "MEG."

Estimates of Reserves and Resources

For information regarding MEG's estimated reserves and resources, please refer to MEG's AIF.

Non-GAAP Financial Measures

Certain financial measures in this MD&A do not have a standardized meaning as prescribed by IFRS including: funds flow from (used in) operations, adjusted funds flow, operating cash flow and total debt. As such, these measures are considered non-GAAP financial measures. These terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. These measures are presented and described in order to provide shareholders and potential investors with additional measures in understanding MEG's ability to generate funds and to finance its operations as well as profitability measures specific to the oil sands industry. The definition and reconciliation of each non-GAAP measure is presented in the "NON-GAAP MEASURES" section of this MD&A.

18. ADDITIONAL INFORMATION

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

19. QUARTERLY SUMMARIES

	2019	2018				2017		
Unaudited	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
FINANCIAL ($000 unless specified)								
Net earnings (loss)	**(47,528)**	(199,360)	118,160	(178,570)	140,573	(23,779)	83,885	104,282
Per share, diluted	**(0.16)**	(0.67)	0.39	(0.61)	0.47	(0.08)	0.28	0.35
Adjusted funds flow	**150,898**	(37,562)	115,742	18,393	83,157	192,178	83,352	55,095
Per share, diluted	**0.50**	(0.13)	0.39	0.06	0.28	0.65	0.28	0.19
Cash capital investment	**53,293**	144,006	144,508	182,567	147,739	163,337	103,173	158,474
Cash and cash equivalents	**154,080**	317,704	372,550	563,969	675,116	463,531	397,598	512,424
Working capital	**174,528**	289,755	274,344	211,045	445,792	313,025	350,067	445,463
Long-term debt	**3,659,547**	3,740,150	3,543,587	3,606,765	3,542,763	4,668,267	4,635,740	4,813,092
Shareholders' equity	**3,850,502**	3,885,538	4,068,048	3,945,782	4,112,531	3,964,113	3,981,750	3,898,054
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**54.90**	58.81	69.50	67.88	62.87	55.40	48.21	48.29
Differential – WTI:WCS – Edmonton (US$/bbl)	**(12.29)**	(39.43)	(22.25)	(19.27)	(24.28)	(12.26)	(9.94)	(11.13)
Differential – WCS:AWB – Edmonton (US$/bbl)	**(2.21)**	(5.17)	(3.44)	(2.94)	(3.17)	(2.30)	(1.89)	(2.00)
AWB – Edmonton (US$/bbl)	**40.40**	14.21	43.81	45.67	35.42	40.84	36.38	35.16
Differential – WTI:AWB – U.S. Gulf Coast (US$/bbl)	**(0.89)**	(6.25)	(5.63)	(7.83)	(7.00)	(5.48)	(6.61)	(7.93)
AWB – U.S. Gulf Coast (US$/bbl)	**54.01**	52.56	63.87	60.05	55.87	49.92	41.60	40.36
C$ equivalent of 1US$ – average	**1.3293**	1.3215	1.3070	1.2911	1.2651	1.2717	1.2524	1.3449
Natural gas – AECO ($/mcf)	**2.86**	1.70	1.28	1.26	2.26	1.84	1.58	2.81
OPERATIONAL ($/bbl unless specified)								
Blend sales, net of purchased product – bbls/d	**132,377**	126,750	130,823	108,237	135,701	135,533	107,600	108,622
Diluent usage – bbls/d	**(42,555)**	(38,467)	(36,967)	(33,819)	(44,093)	(40,992)	(30,787)	(34,506)
Bitumen sales – bbls/d	**89,822**	88,283	93,856	74,418	91,608	94,541	76,813	74,116
Bitumen production – bbls/d	**87,113**	87,582	98,751	71,325	93,207	90,228	83,008	72,448
Steam-oil ratio (SOR)	**2.2**	2.2	2.2	2.2	2.2	2.2	2.3	2.3
Blend sales price	**59.02**	37.76	63.68	62.41	51.20	56.81	48.09	49.89
Bitumen realization	**50.21**	15.31	49.63	47.33	35.46	48.01	39.93	39.74
Transportation – net	**(11.27)**	(10.28)	(9.11)	(8.28)	(5.99)	(7.00)	(7.08)	(6.91)
Royalties	**(0.37)**	(0.15)	(2.01)	(1.64)	(1.03)	(0.84)	(0.53)	(0.87)
Operating costs – non-energy	**(5.22)**	(4.25)	(4.38)	(5.47)	(4.55)	(4.53)	(4.57)	(4.23)
Operating costs – energy	**(3.36)**	(1.98)	(1.50)	(1.79)	(2.64)	(2.03)	(2.26)	(3.76)
Power revenue	**2.41**	1.68	1.54	1.62	1.21	0.70	0.83	0.57
Realized gain (loss) on commodity risk management	**(2.60)**	6.81	(10.16)	(13.11)	(2.15)	(0.77)	0.56	(1.50)
Cash operating netback	**29.80**	7.14	24.01	18.66	20.31	33.54	26.88	23.04
Power sales price (C$/MWh)	**70.83**	55.38	51.53	51.02	35.50	21.37	23.29	18.27
Power sales (MW/h)	**128**	111	117	98	130	129	115	97
Depletion and depreciation rate per bbl of production	**14.68**	13.79	13.85	16.08	13.22	14.26	16.86	16.93
COMMON SHARES								
Shares outstanding, end of period (000)	**296,857**	296,841	296,813	296,751	294,105	294,104	294,079	294,047
Volume traded (000)	**191,935**	151,873	128,363	166,016	89,721	76,531	70,216	98,795
Common share price ($)								
High	**8.62**	11.70	11.51	11.24	6.43	6.82	5.79	7.27
Low	**4.75**	7.25	6.78	4.49	4.28	4.54	3.28	3.63
Close (end of period)	**5.10**	7.71	8.03	10.96	4.55	5.14	5.49	3.81