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 year ended December 31, 2018 was approved by the Board of Directors on March 7, 2019. This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2018, and its most recently filed Annual Information Form ("AIF"). This MD&A and the audited 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.

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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. MEG is not engaged in oil sands mining. MEG uses multiple facilities to transport and sell AWB to refiners throughout North America and beyond.

MEG owns a 100% working interest in over 900 square miles of oil sands leases. In the GLJ Petroleum Consultants Ltd. Report ("GLJ Report"), dated 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. 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. On February 21, 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 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 average approximately 100,000 bbls/d in 2019.

MEG uses multiple facilities to transport and sell AWB to refiners throughout North America and beyond. MEG has contracted for 50,000 bbls/d (expanding to 100,000 bbls/d in 2020) of transportation capacity on the Flanagan South and Seaway pipeline systems providing pipeline transportation directly to U.S. Gulf Coast refineries. 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 committed tidewater access on Canada's West Coast. This combination of pipeline access, along with continuing options for rail and other transportation, 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

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. 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 the Access Pipeline for an initial term of 30 years. The transaction also includes a Stonefell Lease Agreement which is a 30-year arrangement that secures MEG’s operational control and exclusive use of 100% of the Stonefell Terminal’s 900,000-barrel blend and condensate storage facility.

Annual bitumen production averaged 87,731 bbls/d during 2018 compared to 80,774 bbls/d in the prior year. The 9% increase in production is attributable to efficiency gains achieved from eMSAGP at the Christina Lake Project. Adjusted funds flow was $179.7 million for the year ended December 31, 2018 compared to $373.8 million for the year ended December 31, 2017. The decrease was primarily the result of the significant widening of the WTI:WCS differential, particularly during the fourth quarter of 2018, which resulted in a decrease in realized bitumen prices year-over-year, combined with realized losses on commodity risk management contracts during 2018.

In the fourth quarter of 2018, MEG executed a binding agreement to access 30,000 bbls/d of rail loading capacity at a pipeline connected crude-by-rail transloading terminal, operated by Bruderheim Energy Terminal Ltd., a wholly-owned subsidiary of Cenovus (the “Bruderheim Terminal”). This three-year agreement, with a one-year extension at MEG’s option, balances both free-on-board rail sales and delivered rail sales dependent on customer needs, asset availability and market conditions.

On January 22, 2019, the Corporation announced its 2019 capital budget, which includes a base capital budget of $200 million, to be fully funded with expected 2019 adjusted funds flow, and a discretionary capital budget of $75 million, which would not be sanctioned until mid-2019 subject to market conditions at that time. The Corporation is estimating 2019 non-energy operating costs in the range of $4.75 - $5.25 per barrel and bitumen production to average 90,000 - 92,000 bbls/d. The production guidance takes into account a temporary Alberta Government mandated production curtailment, effective January 1, 2019, with easing over the course of the year. If curtailments were not in place, MEG would have the ability to average 100,000 bbls/d in 2019.

In 2019, MEG will continue its strategy towards improving overall cost efficiencies of the organization, strengthening its balance sheet and enhancing its competitive position. In conjunction, the Board is evaluating its composition and has initiated a Board renewal process to ensure that the necessary skillsets and backgrounds are in place to steward the ultimate potential of the Corporation going forward.

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:

	Three months ended December 31		Year ended December 31	
($ millions, except as indicated)	**2018**	**2017**	**2018**	**2017**
Bitumen production - bbls/d	**87,582**	90,228	**87,731**	80,774
Bitumen realization - $/bbl	**13.90**	48.30	**36.25**	41.89
Net operating costs - $/bbl(1)	**4.55**	5.86	**5.09**	6.84
Non-energy operating costs - $/bbl	**4.25**	4.53	**4.62**	4.62
Cash operating netback - $/bbl(2)	**5.73**	33.83	**17.17**	27.00
Adjusted funds flow(3)	**(38)**	192	**180**	374
Per share, diluted(3)	**(0.13)**	0.65	**0.60**	1.29
Operating earnings (loss)(3)	**(118)**	44	**(225)**	(114)
Per share, diluted(3)	**(0.40)**	0.15	**(0.76)**	(0.39)
Revenue(4)	**520**	755	**2,733**	2,474
Net earnings (loss)	**(199)**	(24)	**(119)**	166
Per share, basic	**(0.67)**	(0.08)	**(0.40)**	0.57
Per share, diluted	**(0.67)**	(0.08)	**(0.40)**	0.57
Total cash capital investment	**144**	163	**619**	503
Cash and cash equivalents	**318**	464	**318**	464
Long-term debt	**3,740**	4,668	**3,740**	4,668

(1) Net operating costs include energy and non-energy operating costs, reduced by power revenue.

(2) Cash operating netback is calculated by deducting the related diluent expense, blend purchases, transportation, operating expenses, royalties and realized commodity risk management gains (losses) from proprietary blend revenues and power revenues, on a per barrel of bitumen sales volume basis.

(3) Adjusted funds flow, operating earnings (loss) and the related per share amounts do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The non-GAAP measure of adjusted funds flow is reconciled to net cash provided by (used in) operating activities and the non-GAAP measure of operating earnings (loss) is reconciled to net earnings (loss) in accordance with IFRS, and are 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. FOURTH QUARTER OF 2018

The fourth quarter of 2018 was an exceptionally difficult period for Canadian oil producers due to a rapid decline in Canadian heavy crude oil prices. The primary driver of the fourth quarter results was the significant widening of the WTI:WCS differential, which averaged US$39.43 during the fourth quarter of 2018 compared to US$12.26 during the same period in 2017. The WTI price averaged US$58.81 per barrel for the three months ended December 31, 2018 compared to US$55.40 per barrel for the three months ended December 31, 2017.

Bitumen production in the fourth quarter of 2018 averaged 87,582 bbls/d compared to 90,228 bbls/d in the same period in 2017. The decrease in production was primarily due to the Corporation's direct response to mitigate the effects of the significant widening of the WTI:WCS differential by voluntarily curtailing production. In addition, the Corporation also used this as an opportunity to advance certain 2019 turnaround activities to November 2018.

The Corporation realized a cash operating netback of $5.73 per barrel in the three months ended December 31, 2018, compared to $33.83 per barrel for the three months ended December 31, 2017. The lower cash operating netback was a direct result of the significant widening of the WTI:WCS differential, which resulted in a 36% decrease in the Corporation's blend sales price. The decrease in blend sales price, in combination with an increase in average condensate benchmark prices, decreased bitumen realization. For the three months ended December 31, 2018, bitumen realization averaged $13.90 per barrel compared to $48.30 for the three months ended December 31, 2017. The impact of this was partially offset by a realized net gain on commodity risk management contracts of $6.81 per barrel for the three months ended December 31, 2018, compared to a net loss of $0.77 per barrel for the three months ended December 31, 2017.

Adjusted funds flow was impacted by the same primary factors as cash operating netback, resulting in realized negative adjusted funds flow of $(37.6) million for the three months ended December 31, 2018 compared to adjusted funds flow of $192.2 million for the three months ended December 31, 2017.

Revenue for the three months ended December 31, 2018 totaled $519.8 million compared to $754.8 million for the three months ended December 31, 2017. Revenue decreased primarily as a result of a decrease in average blend sales prices.

The Corporation recognized a net loss of $199.4 million for the three months ended December 31, 2018, which in addition to the impact of depressed Canadian heavy crude oil prices, reflects a net foreign exchange loss of $198.3 million, partially offset by a gain on commodity risk management contracts of $228.0 million. This compares to a net loss of $23.8 million for the three months ended December 31, 2017 which included a loss on commodity risk management of $64.4 million and a net foreign exchange loss of $5.9 million.

Total cash capital investment during the three months ended December 31, 2018 totaled $144.0 million compared to $163.3 million for the three months ended December 31, 2017. Capital investment for the fourth quarter of 2018 was primarily directed towards Phase 2B brownfield expansion.

4. RESULTS OF ANNUAL OPERATIONS

Bitumen Production and Steam-Oil Ratio

	2018	2017
Bitumen production – bbls/d	**87,731**	80,774
Steam-oil ratio (SOR)	**2.2**	2.3

Bitumen Production

Bitumen production for the year ended December 31, 2018 averaged 87,731 bbls/d compared to 80,774 bbls/d for the year ended December 31, 2017. The increase in average production volumes for the year ended December 31, 2018 is primarily due to the efficiency gains achieved from eMSAGP at the Christina Lake Project, with capital spending on the project substantially completed in 2018. Production during both years was impacted by turnaround activities, with the 2018 turnaround having a greater impact on production.

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 year ended December 31, 2018 compared to 2.3 for the year ended December 31, 2017.

Operating Cash Flow

($000)		2018		2017
Petroleum revenue – proprietary[1]	$	2,502,524	$	2,208,577
Blend purchases[2]		(69,695)		(39,975)
Diluent expense		(1,281,075)		(944,134)
		1,151,754		1,224,468
Royalties		(38,205)		(22,578)
Transportation expense		(279,603)		(214,280)
Operating expenses		(209,733)		(222,196)
Power revenue		47,879		22,209
Transportation revenue		11,980		12,801
		684,072		800,424
Realized gain (loss) on commodity risk management		(138,902)		(11,273)
Operating cash flow[3]	$	545,170	$	789,151

(1) *Proprietary petroleum revenue represents MEG's revenue ("blend sales revenue") from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.*
(2) *The Corporation purchases crude oil products from third parties for marketing-related activities.*
(3) *A non-GAAP measure as defined in the "NON-GAAP MEASURES" section of this MD&A.*

Operating cash flow was $545.2 million for the year ended December 31, 2018 compared to $789.2 million for the year ended December 31, 2017. Blend sales revenue increased due to an 8% increase in blend sales volumes and a 4% increase in blend sales price. The WTI benchmark price increased in 2018 by 27% over 2017, which was largely offset by the significant widening of the WTI:WCS differential. Offsetting the increase in blend sales revenue was a $336.9 million increase in diluent expense, a $138.9 million realized loss on commodity risk management and a $65.3 million increase in transportation expense.

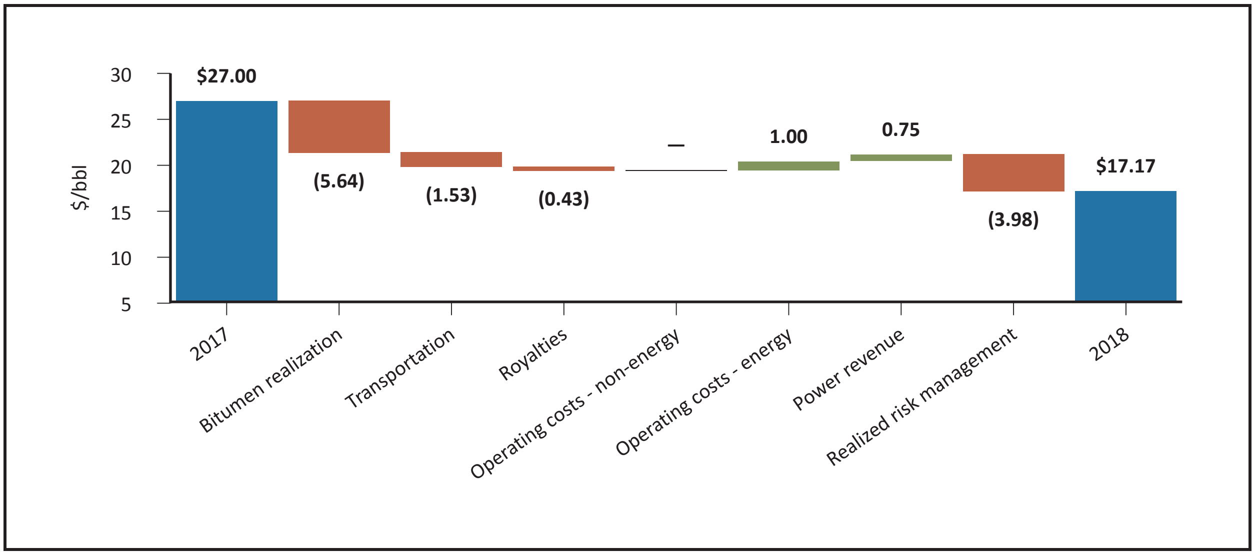
Cash Operating Netback

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

($/bbl)		2018		2017
Blend sales price[1]	$	53.26	$	51.20
Bitumen realization[2]	$	36.25	$	41.89
Transportation[3]		(8.42)		(6.89)
Royalties		(1.20)		(0.77)
		26.63		34.23
Operating costs – non-energy		(4.62)		(4.62)
Operating costs – energy		(1.98)		(2.98)
Power revenue		1.51		0.76
Net operating costs		(5.09)		(6.84)
Cash operating netback excluding realized commodity risk management		21.54		27.39
Realized gain (loss) on commodity risk management		(4.37)		(0.39)
Cash operating netback	$	17.17	$	27.00

(1) Blend sales revenue on a per barrel of blend sales volume basis.
(2) Blend sales revenue net of blend purchases and diluent expense.
(3) Defined as transportation expense less transportation revenue. Transportation includes pipeline, rail and storage costs, net of third-party recoveries on diluent transportation arrangements.

Cash Operating Netback



Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary petroleum revenue ("blend sales revenue"), net of blend purchases and diluent expense, expressed on a per barrel 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. A portion of diluent expense is effectively recovered in the sales price of the blended product. 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.

Bitumen realization averaged $36.25 per barrel for the year ended December 31, 2018, compared to $41.89 per barrel for the year ended December 31, 2017. In contrast to the 27% increase in the WTI benchmark price, the Corporation realized an average blend sales price increase of 4% for the year ended December 31, 2018 compared to the same period in 2017 as a direct result of the significant widening of the WTI:WCS differential. To mitigate the effects of the significant widening of the WTI:WCS differential, approximately 30% of blend sales volumes were delivered to the U.S. Gulf Coast, where sales pricing is not subject to the same heavy oil differential. The Corporation's cost of diluent increased to $91.60 per barrel of diluent for the year ended December 31, 2018 compared to $72.32 per barrel of diluent for the year ended December 31, 2017, primarily due to the increase in average condensate benchmark pricing.

Transportation

The Corporation utilizes a network of pipelines, rail and storage facilities to optimize market access. Sales volumes destined for the U.S. Gulf Coast require additional transportation costs, but generally obtain higher sales prices.

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 year ended December 31, 2018, transportation costs averaged $8.42 per barrel compared to $6.89 per barrel for the year ended December 31, 2017. The increase in costs on a per barrel basis is primarily the result of incremental transportation costs associated with the TSA and additional costs associated with increased volumes transported by rail to the U.S Gulf Coast. The per barrel increase is partially offset by larger sales volumes for the year ended December 31, 2018, compared to the same period in 2017.

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 $1.20 per barrel for the year ended December 31, 2018, compared to $0.77 per barrel for the year ended December 31, 2017. The increase in royalties per barrel is primarily the result of higher WTI crude oil prices.

Net Operating Costs

Net operating costs are comprised of the sum of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-related operating activities. Energy operating costs reflect the cost of natural gas for the production of steam and power at the Corporation’s facilities. Power revenue is the sale of surplus power generated by the Corporation’s cogeneration facilities at the Christina Lake Project.

Net operating costs for the year ended December 31, 2018 averaged $5.09 per barrel compared to $6.84 per barrel for the year ended December 31, 2017. The decrease in net operating costs is primarily the result of a per barrel decrease in energy operating costs and an increase in per barrel power revenue.

Non-energy operating costs

Non-energy operating costs averaged $4.62 per barrel for each of the years ended December 31, 2018, and 2017. Additional production-related costs were largely offset by higher sales volumes for the year ended December 31, 2018 compared to 2017.

Energy operating costs

Energy operating costs averaged $1.98 per barrel for the year ended December 31, 2018 compared to $2.98 per barrel for the year ended December 31, 2017. The decrease in energy operating costs is primarily attributable to lower natural gas prices. The Corporation’s natural gas purchase price averaged $1.88 per mcf during the year ended December 31, 2018 compared to $2.59 per mcf in 2017.

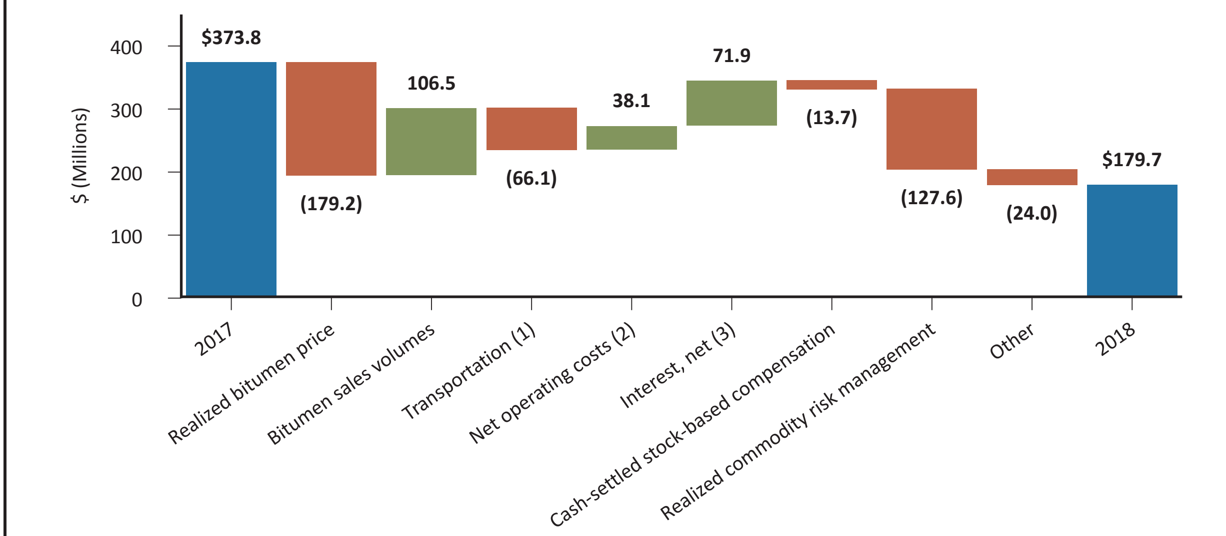
Power revenue

Power revenue averaged $1.51 per barrel for the year ended December 31, 2018 compared to $0.76 per barrel for the year ended December 31, 2017. The Corporation’s average realized power sales price during the year ended December 31, 2018 was $47.87 per megawatt hour compared to $21.49 per megawatt hour in 2017. The higher average realized price is attributable to higher Alberta power pool prices, partially due to the introduction of a higher carbon tax levy at the beginning of 2018, in combination with the retirement and suspension of older coal-fired power plants in the province of Alberta.

Realized Gain or Loss on Commodity Risk Management

The Corporation has entered into financial commodity risk management contracts to protect a portion of its capital program. The realized loss on commodity risk management averaged $4.37 per barrel for the year ended December 31, 2018 compared to a realized loss of $0.39 per barrel for the year ended December 31, 2017. 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.

(2) Includes non-energy and energy operating costs, reduced by power revenue.

(3) Defined as net interest expense plus realized gain(loss) on interest rate swaps less interest expense on finance leases less amortization of debt discount and debt issue costs.

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 decreased to $179.7 million for the year ended December 31, 2018 from $373.8 million for the year ended December 31, 2017. The decrease in adjusted funds flow was primarily the result of the significant widening of the WTI:WCS differential and an increase in diluent expense, which resulted in lower realized bitumen prices, combined with a significant increase in realized losses on commodity risk management contracts. These items were partially offset by higher sales volumes and a reduction in net interest expense.

Operating Earnings (Loss)

The Corporation recognized an operating loss $225.4 million for the year ended December 31, 2018 compared to an operating loss of $113.5 million for the year ended December 31, 2017. The increase in the operating loss was primarily due to lower bitumen realization and an increase in realized losses on commodity risk management contracts, partially offset by higher bitumen sales volumes.

Operating earnings (loss) is a non-GAAP measure, as defined in the "NON-GAAP MEASURES" section of this MD&A, which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating earnings (loss) is reconciled to "Net earnings (loss)", the nearest IFRS measure, in the table below.

($000)	2018	2017
Net earnings (loss)	$ (119,197)	$ 165,976
Adjustments:		
Unrealized loss (gain) on foreign exchange(1)	340,753	(338,144)
Unrealized loss (gain) on derivative financial liabilities(2)	3,096	(16,179)
Unrealized loss (gain) on commodity risk management(3)	(161,373)	38,336
Realized foreign exchange loss (gain) on foreign exchange derivatives(4)	(35,362)	—
Gain on asset dispositions(5)	(325,031)	—
Defense costs related to unsolicited bid(6)	19,152	—
Onerous contracts expense	3,296	10,830
Contract cancellation expense(7)	—	18,765
Debt extinguishment expense(8)	—	30,801
Insurance proceeds	—	(183)
Deferred tax expense (recovery) relating to these adjustments	49,306	(23,726)
Operating earnings (loss)(9)	$ (225,360)	$ (113,524)

(1) *Unrealized net foreign exchange gains and losses arising from the translation of U.S. dollar denominated long-term debt and cash and cash equivalents using year-end exchange rates.*

(2) *Unrealized gains and losses on derivative financial liabilities arising from the interest rate floor on the Corporation's long-term debt and interest rate swaps entered into to effectively fix a portion of its variable rate long-term debt.*

(3) *Unrealized gains or losses on commodity risk management contracts represent the change in the mark-to-market position of unsettled commodity risk management contracts during the year.*

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

(5) *A gain primarily related to the sale of the Corporation's 50% interest in the Access Pipeline.*

(6) *The Corporation incurred costs of $19.2 million in the fourth quarter of 2018 related to Husky Energy Inc.'s unsolicited bid to acquire all of the outstanding shares of the Corporation.*

(7) *During the third quarter of 2017, the Corporation recognized a contract cancellation expense of $18.8 million relating to the termination of a long-term marketing transportation contract that had not yet commenced.*

(8) *At December 31, 2017 the Corporation recognized debt extinguishment expense of $30.8 million associated with the planned repayment of approximately C$1.225 billion of the senior secured term loan.*

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

Revenue

Revenue represents the total of petroleum revenue, net of royalties and other revenue. Revenue for the year ended December 31, 2018 totaled $2.7 billion compared to $2.5 billion for the year ended December 31, 2017. Revenue increased as a result of an increase in blend sales volumes and an increase in the average blend sales price.

Net Earnings (Loss)

The Corporation recognized a net loss of $119.2 million for the year ended December 31, 2018 compared to net earnings of $166.0 million for the year ended December 31, 2017. The net loss for the year ended December 31, 2018 included a net foreign exchange loss of $311.2 million compared to a net foreign exchange gain of $342.5 million for the year ended December 31, 2017. The net loss for the year ended December 31, 2018 also included a gain on commodity risk management contracts of $22.5 million compared to a loss on commodity risk management contracts of $49.6 million for 2017. The 2018 net loss includes a gain on asset dispositions of $325.0 million, primarily related to the sale of the Corporation's 50% interest in the Access Pipeline.

Total Cash Capital Investment

Total cash capital investment for the year ended December 31, 2018 was $618.8 million, compared to $502.8 million for the year ended December 31, 2017. Capital investment in 2018 was primarily directed towards the Corporation's phase 2B brownfield expansion and sustaining capital initiatives at Christina Lake Phase 2B.

5. OUTLOOK

Summary of 2018 Guidance	Guidance	Annual Results
Total cash capital investment	$670 million	**$619 million**
Bitumen production – annual average (bbls/d)	87,000 – 90,000	**87,731**
Non-energy operating costs ($/bbl)	$4.50 – $5.00	**$4.62**
Bitumen production – targeted exit volume (bbls/d)	95,000 – 100,000	**84,883**

Capital investment for 2018 was $619 million, which was below the Corporation's most recent 2018 capital investment guidance of $670 million. The decrease was a result of reducing planned capital spending in response to the significant widening of the WTI:WCS differential during the fourth quarter of 2018. Improved capital cost efficiencies and strong operational results from the implementation of eMSAGP at the Christina Lake project allowed the Corporation to achieve average annual bitumen production of 87,731 bbls/d and average annual non-energy operating costs of $4.62/bbl, which were both consistent with the Corporation's most recent 2018 guidance.

Exit bitumen production volume, defined as the average production in the month of December 2018, was 84,883 bbls/d. Despite having production capability of approximately 100,000 bbls/d, the Corporation reduced planned production in direct response to the significant widening of the WTI:WCS differential during the fourth quarter of 2018 and in anticipation of a temporary Alberta Government mandated production curtailment, effective January 1, 2019.

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 terminate December 31, 2019. The Curtailment Rules give the Minister the authority to make an Order to set the maximum combined provincial production amount of crude oil and bitumen on a monthly basis. The Minister also has the authority to make an Order to set the curtailment amount for each operator. The Alberta Energy Regulator ("AER") is responsible for ensuring that operators comply with the Curtailment Rules and their individual ministerial orders. Operators that do not comply will be subject to AER enforcement action.

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, $40 million towards growth capital which includes both 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 expects to fully fund the capital program with expected 2019 adjusted funds flow.

A discretionary capital budget of $75 million will be reviewed mid-2019, and would be subject to market conditions. Additional capital would be directed to MEG's Phase 2B brownfield expansion, which would enable the Corporation to achieve its previously announced target of reaching 113,000 bbls/d of bitumen production in 2020.

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 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 G&A costs of $1.95 - $2.05 per barrel.

6. 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:

	Year ended December 31		2018				2017			
	2018	**2017**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**71.53**	54.83	**68.08**	75.97	74.90	67.18	61.54	52.18	50.93	54.66
WTI (US$/bbl)	**64.77**	50.95	**58.81**	69.50	67.88	62.87	55.40	48.21	48.29	51.91
WTI (C$/bbl)	**83.95**	66.13	**77.72**	90.84	87.64	79.54	70.45	60.38	64.94	68.68
WCS (C$/bbl)	**49.85**	50.58	**25.61**	61.76	62.76	48.82	54.86	47.93	49.98	49.39
Differential – WTI:WCS (US$/bbl)	**26.31**	11.98	**39.43**	22.25	19.27	24.28	12.26	9.94	11.13	14.58
Differential – WTI:WCS (%)	**40.6%**	23.5%	**67.0%**	32.0%	28.4%	38.6%	22.1%	20.6%	23.0%	28.1%
Condensate prices										
Condensate at Edmonton (C$/bbl)	**78.88**	66.91	**59.63**	87.35	88.84	79.72	73.72	59.59	65.16	69.17
Condensate at Edmonton as % of WTI	**94.0%**	101.2%	**76.7%**	96.2%	101.4%	100.2%	104.6%	98.7%	100.3%	100.7%
Condensate at Mont Belvieu, Texas (US$/bbl)	**59.85**	48.14	**51.21**	64.53	64.40	59.27	55.35	46.37	44.77	46.05
Condensate at Mont Belvieu, Texas as % of WTI	**92.4%**	94.5%	**87.1%**	92.8%	94.9%	94.3%	99.9%	96.2%	92.7%	88.7%
Natural gas prices										
AECO (C$/mcf)	**1.62**	2.29	**1.70**	1.28	1.26	2.26	1.84	1.58	2.81	2.91
Electric power prices										
Alberta power pool (C$/MWh)	**50.19**	22.17	**55.57**	54.46	55.92	34.81	22.49	24.55	19.26	22.38
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.2962**	1.2980	**1.3215**	1.3070	1.2911	1.2651	1.2717	1.2524	1.3449	1.3230
C$ equivalent of 1 US$ - period end	**1.3646**	1.2518	**1.3646**	1.2924	1.3142	1.2901	1.2518	1.2510	1.2977	1.3322

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$64.77 per barrel for the year ended December 31, 2018 compared to US$50.95 per barrel for the year ended December 31, 2017.

WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. The WCS benchmark reflects North American heavy oil prices at Hardisty, Alberta. WCS typically trades at a differential below the WTI benchmark price. The WTI:WCS differential averaged US$26.31 per barrel, or 40.6% of WTI, for the year ended December 31, 2018 compared to US$11.98 per barrel, or 23.5% of WTI, for the year ended December 31, 2017. The WTI:WCS differential has widened as a result of increased Canadian heavy oil production in conjunction with a lack of sufficient export pipeline capacity and delays affecting the ramp-up of major rail carriers' capacity. Beginning in January 2019, in conjunction with the provincially mandated curtailments for the industry and the increase in overall crude by rail exports, commodity prices have improved significantly.

Condensate Prices

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

Condensate prices, benchmarked at Edmonton, averaged $78.88 per barrel, or 94.0% of WTI, for the year ended December 31, 2018 compared to $66.91 per barrel, or 101.2% of WTI, for the year ended December 31, 2017. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$59.85 per barrel, or 92.4% of WTI, for the year ended December 31, 2018 compared to US$48.14 per barrel, or 94.5% of WTI, for the year ended December 31, 2017.

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 $1.62 per mcf for the year ended December 31, 2018 compared to $2.29 per mcf for the year ended December 31, 2017. The AECO natural gas price has decreased as a result of increased natural gas production in Alberta, coupled with continued pipeline constraints and lack of domestic 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 $50.19 per megawatt hour for the year ended December 31, 2018 compared to $22.17 per megawatt hour for the year ended December 31, 2017. Alberta power pool prices have increased partially due to the introduction of a higher carbon tax levy at the beginning of 2018, in combination with the retirement and suspension of older coal-fired power plants 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 a portion of 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 December 31, 2018, the Canadian dollar, at a rate of 1.3646, had decreased in value by approximately 9% against the U.S. dollar compared to its value as at December 31, 2017, when the rate was 1.2518.

7. OTHER OPERATING RESULTS

Net Marketing Activity

($000)	2018	2017
Petroleum revenue – third party	**$ 208,526**	$ 253,486
Third party purchased product	**(194,564)**	(250,681)
Net marketing activity[1]	**$ 13,962**	$ 2,805

(1) *Net marketing activity is a non-GAAP measure as defined in the "NON-GAAP MEASURES" section.*

The Corporation has entered into marketing arrangements for rail and pipeline transportation commitments and product storage arrangements to enhance its ability to transport proprietary crude oil products to a wider range of markets in Canada, the United States and on tidewater. In the event that the Corporation is not utilizing these arrangements for proprietary purposes, the Corporation purchases and sells third-party crude oil and related products and enters into transactions to generate revenues to offset the costs of such marketing and storage arrangements.

Depletion and Depreciation

($000)		2018		2017
Depletion and depreciation expense	**$**	**452,178**	$	475,644
Depletion and depreciation expense per barrel of production	**$**	**14.12**	$	16.13

Depletion and depreciation expense per barrel decreased in 2018 from 2017, primarily due to a significant reduction in estimated future development costs associated with the Corporation's proved reserves. Future development costs are derived from the Corporation's independent reserve report and are a key element of the rate determination. The decrease in future development costs is primarily related to the Corporation's future growth strategy, which anticipates reduced capital requirements to produce the reserves.

Commodity Risk Management Gain (Loss)

The Corporation has entered into financial commodity risk management contracts to protect a portion of its capital program. 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 year. 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 year.

($000)	2018			2017		
	Realized	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude oil contracts[1]	**$ (126,797) $**	**194,469 $**	**67,672**	$ (53,364) $	(9,245) $	(62,609)
Condensate contracts[2]	**(12,105)**	**(33,096)**	**(45,201)**	42,091	(29,091)	13,000
Commodity risk management gain (loss)	**$ (138,902) $**	**161,373 $**	**22,471**	$ (11,273) $	(38,336) $	(49,609)

(1) *Includes WTI fixed price, WTI collars and WTI:WCS fixed differential contracts.*
(2) *Relates to condensate purchase contracts that effectively fix condensate prices as a percentage of WTI at Mont Belvieu, Texas.*

The Corporation realized a net loss on commodity risk management contracts of $138.9 million for the year ended December 31, 2018, primarily due to net settlement losses on contracts relating to crude oil sales. This compares to a realized net loss of $11.3 million for the year ended December 31, 2017. WTI fixed price contracts, which fixed prices at approximately US$54 per barrel, and WTI collars, which established a ceiling price at approximately US$54 per barrel, settled, on average, at approximately US$65 per barrel during the year ended December 31, 2018. The realized losses from the settlement of these contracts were partially offset by gains on WTI:WCS fixed differential contracts, which fixed the differential at approximately US$15 per barrel and settled, on average, at approximately US$26 per barrel.

The Corporation recognized an unrealized net gain on commodity risk management contracts of $161.4 million for the year ended December 31, 2018, reflecting net unrealized gains on crude oil contracts partially offset by unrealized losses on condensate purchase contracts. The net unrealized gains on crude oil contracts were the result of crude oil benchmark forward prices decreasing over the contract periods, resulting in unrealized gains on the Corporation's WTI fixed price contracts, partially offset by narrowing WTI:WCS forward differentials, which resulted in unrealized losses on WTI:WCS fixed differential contracts. The $161.4 million unrealized gain for the year ended December 31, 2018 compares to a $38.3 million unrealized loss in 2017. Refer to the "Risk Management" section of this MD&A for further details.

General and Administrative

($000)		2018		2017
General and administrative expense	$	82,686	$	86,785
General and administrative expense per barrel of production	$	2.58	$	2.94

General and administrative expense per barrel decreased 12% for the year ended December 31, 2018 to $2.58 per barrel, from $2.94 per barrel for the year ended December 31, 2017. The per barrel decrease was primarily due to a 9% increase in production.

Stock-based Compensation

($000)		2018		2017
Cash-settled expense	$	25,539	$	3,476
Equity-settled expense		21,584		19,052
Stock-based compensation	$	47,123	$	22,528

Stock-based compensation expense for the year ended December 31, 2018 was $47.1 million compared to $22.5 million for the year ended December 31, 2017. The increase was primarily a result of an increase in the fair value of the cash-settled units due to an increase in the Corporation's common share price, combined with an increase in the performance factor applicable to performance share units ("PSUs"). As at December 31, 2018, the Corporation's common share price increased by approximately 50% compared to its value on December 31, 2017.

Foreign Exchange Gain (Loss), Net

($000)		2018		2017
Unrealized foreign exchange gain (loss) on:				
Long-term debt	$	(345,542)		343,633
Other		4,789		(5,489)
Unrealized net gain (loss) on foreign exchange		(340,753)		338,144
Realized gain (loss) on foreign exchange		(5,771)		4,403
Realized gain (loss) on foreign exchange derivatives		35,362		—
Foreign exchange gain (loss), net	$	(311,162)	$	342,547

C$ equivalent of 1 US$	2018	2017
Beginning of year	1.2518	1.3427
End of year	1.3646	1.2518

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 year ended December 31, 2018, the Canadian dollar weakened by 9%, resulting in an unrealized foreign exchange loss on translation of U.S. dollar denominated debt of $345.5 million. For the year ended December 31, 2017, the Canadian dollar strengthened by 7%, resulting in an unrealized foreign exchange gain on translation of U.S. dollar denominated debt of $343.6 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

($000)		2018		2017
Interest expense on long-term debt	$	287,417	$	341,594
Interest expense on finance leases		12,783		—
Interest income		(7,641)		(3,924)
Net interest expense		292,559		337,670
Debt extinguishment expense		—		30,801
Accretion on provisions		7,637		7,760
Unrealized loss (gain) on derivative financial liabilities[1]		3,096		(16,179)
Realized loss (gain) on interest rate swaps		(17,312)		1,028
Net finance expense	$	285,980	$	361,080
Average effective interest rate[2]		6.4%		6.1%

(1) *Derivative financial liabilities include the 1% interest rate floor and interest rate swaps.*
(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 interest rate swaps.*

Interest expense on long-term debt for the year ended December 31, 2018 was $287.4 million compared to $341.6 million for the year ended December 31, 2017. The interest expense decrease for the year ended December 31, 2018 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 year ended December 31, 2018. The repayment also reduced the estimated amortization period of the unamortized debt discount and debt issue costs, and the unamortized financial derivative liability discount. The change in estimate was an adjusting subsequent event under IAS 10, Events after the Reporting Period, and a debt extinguishment expense of $30.8 million was recorded for the year ended December 31, 2017. The debt extinguishment expense was comprised of the unamortized proportion of the senior secured term loan debt discount and debt issue costs of $17.0 million and the unamortized proportion of the senior secured term loan financial derivative liability discount of $13.8 million.

Other Expenses

($000)		2018		2017
Defense costs related to unsolicited bid	$	19,152	$	—
Severance and other		5,445		4,948
Onerous contracts expense		3,296		10,830
Contract cancellation expense		—		18,765
Other expenses	$	27,893	$	34,543

On October 2, 2018, Husky Energy Inc. ("Husky") issued an unsolicited Offer to Purchase and Bid Circular to acquire all of the outstanding common shares of the Corporation. The Corporation issued a Directors' Circular on October 17, 2018, recommending that shareholders reject Husky's offer. On January 17, 2019, Husky issued a press release stating that the takeover offer for the Corporation did not meet their minimum tender conditions and therefore did not extend the offer. During the fourth quarter of 2018, the Corporation incurred $19.2 million of costs related to Husky's offer.

Onerous contracts expense primarily includes changes in estimated future cash flow sublease recoveries related to the onerous office lease provision for the Corporation's office building lease contracts.

During the third quarter of 2017, the Corporation recognized contract cancellation expense of $18.8 million relating to the termination of a long-term marketing transportation contract that had not yet commenced.

Income Tax Expense (Recovery)

($000)		**2018**		**2017**
Current income tax expense (recovery)	$	**903**	$	(67)
Deferred income tax expense (recovery)		**(49,679)**		(56,130)
Income tax expense (recovery)	$	**(48,776)**	$	(56,197)

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 December 31, 2018, the Corporation had approximately $7.7 billion of available Canadian tax pools.

The Corporation recognized a current income tax expense of $0.9 million for the year ended December 31, 2018 and a current income tax recovery of $0.1 million for the year ended December 31, 2017. The 2018 expense of $0.9 million is related to United States income tax associated with operations in the United States. The 2017 recovery is comprised of $0.8 million related to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures, partially offset by an expense of $0.7 million related to United States income tax associated with its operations in the United States.

The Corporation recognized a deferred income tax recovery of $49.7 million for the year ended December 31, 2018 and a deferred income tax recovery of $56.1 million for the year ended December 31, 2017.

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

- The permanent difference due to capital gains arising on the disposition of the Access Pipeline and the Stonefell Terminal, and gains on foreign exchange derivatives. For the year ended December 31, 2018, capital gains of $365.6 million were sheltered by capital loss carry forwards not previously recognized.

- 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 year ended December 31, 2018, the non-taxable loss was $172.8 million compared to a non-taxable gain of $171.9 million for the year ended December 31, 2017.

- Non-taxable stock-based compensation expense for equity-settled plans is a permanent difference. Stock-based compensation expense for equity-settled plans for the year ended December 31, 2018 was $21.6 million compared to $19.1 million for the year ended December 31, 2017.

As at December 31, 2018, the Corporation has recognized a deferred income tax asset of $236.6 million on the Consolidated Balance Sheet, as estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

As at December 31, 2018, the Corporation had not recognized the tax benefit related to $435.7 million of realized and unrealized taxable foreign exchange losses.

8. NET CAPITAL INVESTMENT

($000)	2018	2017
eMSAGP growth capital	$ 89,774	$ 222,982
eMVAPEX growth capital	64,829	32,612
Phase 2B brownfield expansion	166,462	—
Growth capital	321,065	255,594
Sustaining and maintenance	250,688	189,288
Field infrastructure, corporate and other	47,067	57,872
Total cash capital investment	618,820	502,754
Capitalized cash-settled stock-based compensation	3,429	(308)
	$ 622,249	$ 502,446

Total cash capital investment for the year ended December 31, 2018 was $618.8 million, compared to $502.8 million for the year ended December 31, 2017. The increase in capital investment for the year ended December 31, 2018 was primarily related to increased spending on the eMVAPEX and Phase 2B brownfield growth projects. Investment in sustaining capital activities for the year ended December 31, 2018 included approximately $64.0 million of turnaround costs of which $56.0 million were primarily incurred in the second quarter of 2018, with the remaining $8.0 million relating to the advancement of 2019 turnaround activities to November 2018. In comparison, for the year ended December 31, 2017, sustaining capital activities included approximately $37.1 million in turnaround costs.

9. SUMMARY OF QUARTERLY RESULTS

The following table summarizes selected financial information for the Corporation for the preceding eight quarters:

	2018				2017			
($ millions, except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue[(1)]	$ 519.8	$ 803.2	$ 689.1	$ 720.6	$ 754.8	$ 576.3	$ 583.6	$ 559.8
Net earnings (loss)	(199.4)	118.2	(178.6)	140.6	(23.8)	83.9	104.3	1.6
Per share - basic	(0.67)	0.40	(0.61)	0.48	(0.08)	0.29	0.36	0.01
Per share - diluted	(0.67)	0.39	(0.61)	0.47	(0.08)	0.28	0.35	0.01

(1) 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 periods have been revised to reflect the new presentation.

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

- fluctuations in blend sales pricing due to significant changes in the price of WTI and the differential between WTI and the Corporation's AWB;
- the cost of diluent due to changes in Canadian and U.S. benchmark pricing and the timing of diluent inventory purchases;
- changes in the value of the Canadian dollar relative to the U.S. dollar and its impact on blend sales prices, the cost of diluent, interest expense, and foreign exchange gains and losses associated with the Corporation's U.S. dollar denominated debt;

- increased bitumen production volumes due to efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project, which has allowed additional wells to be placed into production;
- fluctuations in natural gas and power pricing;
- gains and losses on commodity risk management contracts;
- a first quarter 2018 gain on asset disposition related to the Corporation's sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal; and
- changes in depletion and depreciation expense as a result of changes in production rates and future development costs.

10. SUMMARY OF ANNUAL INFORMATION

($ millions, except per share amounts)	2018	2017	2016
Revenue[1]	**$ 2,732.7**	$ 2,474.5	$ 1,866.3
Net earnings (loss)	**(119.2)**	166.0	(428.7)
Per share - basic	**(0.40)**	0.57	(1.90)
Per share - diluted	**(0.40)**	0.57	(1.90)
Total assets	**8,409.5**	9,363.4	8,921.2
Total non-current liabilities	**4,057.6**	4,873.8	5,271.3

(1) 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 year amounts have been revised to reflect the new presentation.

Revenue

During 2018, revenue increased 10% from 2017, primarily as a result of the year-over-year increased production and resulting increased blend sales volumes.

During 2017, revenue increased 33% from 2016, primarily as a result of the year-over-year average increase in crude oil benchmark pricing.

Net Earnings (Loss)

The decrease in net earnings in 2018 compared to net earnings in 2017 is primarily attributable to the net foreign exchange loss in 2018 compared to a net foreign exchange gain in 2017. The change in value of the Canadian dollar relative to the U.S. dollar impacts the translation of the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. In addition, diluent expense increased due to higher condensate benchmark prices in 2018, as well as incremental condensate volumes required for blending purposes. These factors were partially offset by a gain on asset dispositions relating to the sale of the Corporation's 50% interest in the Access Pipeline.

The increase in net earnings in 2017 compared to the net loss in 2016 is primarily attributable to higher bitumen realization as a result of the increase in average crude oil benchmark pricing in 2017. In addition, the net unrealized foreign exchange gain increased in 2017 compared to 2016. The change in value of the Canadian dollar relative to the U.S. dollar impacts the translation of the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.

Total Assets

Total assets as at December 31, 2018 decreased compared to December 31, 2017 primarily due to the asset dispositions relating to the sale of the Corporation's 50% interest in Access Pipeline and 100% interest in the Stonefell terminal.

Total assets as at December 31, 2017 increased compared to December 31, 2016 primarily due to an increase in cash as a result of the equity issuance pursuant to the comprehensive refinancing that closed on January 27, 2017.

For a detailed discussion of the Corporation’s investing activities, see "LIQUIDITY AND CAPITAL RESOURCES – Cash Flow – Investing Activities".

Total Non-Current Liabilities

Total non-current liabilities as at December 31, 2018 decreased compared to December 31, 2017 primarily due to the repayment of approximately C$1.2 billion of the Corporation’s senior secured term loan in 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. This was partially offset by a C$0.3 billion increase in unrealized foreign exchange losses on the translation of the U.S. dollar denominated debt as a result of the weakening Canadian dollar compared to the U.S. dollar by approximately 9% during the year.

Total non-current liabilities as at December 31, 2017 decreased compared to December 31, 2016 primarily due to the Corporation recognizing an unrealized foreign exchange gain on the translation of the U.S. dollar denominated debt as a result of strengthening of the Canadian dollar compared to the U.S. dollar by approximately 7% during the year.

11. LIQUIDITY AND CAPITAL RESOURCES

($000)	**December 31, 2018**	**December 31, 2017**
Cash and cash equivalents	**$ 317,704**	$ 463,531
Senior secured term loan (December 31, 2018 – US$225.4 million; due 2023; December 31, 2017 – US$1.226 billion)	**307,552**	1,534,378
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,091,640**	1,001,440
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,364,550**	1,251,800
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**1,023,413**	938,850
US$1.4 billion revolving credit facility (due 2021)	**—**	—
Total debt(1)(2)	**$ 3,787,155**	$ 4,726,468

(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+. The 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

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. A majority of the net cash proceeds were used to repay approximately C$1.2 billion of MEG's senior secured term loan. Total debt decreased to C$3.8 billion as at December 31, 2018 from C$4.7 billion as at December 31, 2017 as a result of the C$1.2 billion repayment, partially offset by a C$0.3 billion increase as a result of unrealized foreign exchange losses on translation of the U.S dollar denominated debt.

The Corporation's cash and cash equivalents balance was $317.7 million as at December 31, 2018 compared to $463.5 million as at December 31, 2017. As at December 31, 2018, no amount had been drawn under the Corporation’s US $1.4 billion revolving credit facility.

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 December 31, 2018, the Corporation had US$141.1 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 with the intent of increasing the predictability of the Corporation’s future cash flow. 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. MEG's hedging philosophy over the last two years has been focused on protecting a portion of its capital program. With current cash reserves and higher commodity prices, the Corporation expects to hedge a substantially lower proportion of its barrels going forward.

The Corporation had the following financial commodity risk management contracts relating to crude oil sales and condensate purchases outstanding as at December 31, 2018:

As at December 31, 2018	Volumes (bbls/d)(1)	Term	Average Price (US$/bbl)(1)
Crude Oil Sales Contracts			
Fixed Price:			
WTI Fixed Price	21,115	Jan 1, 2019 - Dec 31, 2019	$67.30
WTI:WCS Fixed Differential	31,000	Jan 1, 2019 - Dec 31, 2019	$(24.28)
WTI:WCS Fixed Differential	5,000	Jan 1, 2020 - Dec 31, 2020	$(23.19)
Options:			
Purchased WTI Puts	1,000	Jan 1, 2019 - Mar 31, 2019	$55.00
Condensate Purchase Contracts			
Fixed Percentage:			
Mont Belvieu Fixed % of WTI	9,750	Jan 1, 2019 - Dec 31, 2019	92.2% of WTI
Mont Belvieu Fixed % of WTI	7,750	Jan 1, 2020 - Dec 31, 2020	93.1% of WTI

The Corporation entered into the following commodity risk management contracts relating to crude oil sales between January 1, 2019 and March 6, 2019:

Subsequent to December 31, 2018	Volumes (bbls/d)(1)	Term	Average Prices (US$/bbl)(1)
Crude Oil Sales Contracts			
Fixed Price:			
WTI Fixed Price	2,058	Feb 1, 2019 - Mar 31, 2019	$53.23
WTI:WCS Fixed Differential	10,568	Feb 1, 2019 - Dec 31, 2019	$(17.09)
WTI:WCS Fixed Differential	2,000	Jan 1, 2020 - Dec 31, 2020	$(20.73)
Condensate Purchase Contracts			
Fixed Price:			
WTI:Mont Belvieu Fixed Differential	3,000	Apr 1, 2019 - Dec 31, 2019	$(7.55)
WTI:Mont Belvieu Fixed Differential	2,500	Jan 1, 2020 - Dec 31, 2020	$(7.42)

(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. The Corporation did not have any outstanding interest rate swap contracts as at December 31, 2018.

Cash Flow Summary

		Year ended December 31		
($000)		**2018**		**2017**
Net cash provided by (used in):				
Operating activities	**$**	**280,032**	$	317,935
Investing activities		**851,078**		(405,231)
Financing activities		**(1,283,693)**		401,245
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**6,756**		(6,648)
Change in cash and cash equivalents	**$**	**(145,827)**	$	307,301

Cash Flow – Operating Activities

Net cash provided by operating activities totaled $280.0 million for the year ended December 31, 2018 compared to $317.9 million for the year ended December 31, 2017. This decrease in cash flows is largely due to the significant widening of the WTI:WCS differential in combination with an increase in diluent expense, due to higher condensate benchmark prices and an increase in condensate volumes, as well as realized losses on commodity risk management. These were partially offset by higher blend sales, primarily as a result of an increase in blend sales volumes.

Cash Flow – Investing Activities

Net cash provided by investing activities was $851.1 million for the year ended December 31, 2018 compared to net cash used in investing activities of $405.2 million for the year ended December 31, 2017. The increase in investing activity cash flows is due to the receipt of 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, which closed in the first quarter of 2018, partially offset by increased capital investing activity.

Cash Flow – Financing Activities

Net cash used in financing activities was $1.3 billion for the year ended December 31, 2018 compared to net cash provided by financing activities of $401.2 million for the year ended December 31, 2017. Net cash used in financing activities 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. Net cash provided by financing activities for the year ended December 31, 2017 included $496.3 million of net equity issuance proceeds, partially offset by costs of $82.4 million paid as part of the comprehensive refinancing plan in early 2017.

12. SHARES OUTSTANDING

As at December 31, 2018, the Corporation had the following share capital instruments outstanding or exercisable:

(000)	**Units**
Common shares	**296,841**
Convertible securities	
Stock options[1]	**8,517**
Equity-settled RSUs and PSUs	**6,534**

(1) 6.7 million stock options were exercisable as at December 31, 2018.

As at March 5, 2019, the Corporation had 296.8 million common shares, 8.4 million stock options and 6.2 million equity-settled restricted share units and equity-settled performance share units outstanding, and 6.7 million stock options exercisable.

13. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

a. 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 December 31, 2018. 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 repayments or redemptions.

($000)	**2019**	**2020**	**2021**	**2022**	**2023**	**Thereafter**	**Total**
Transportation and storage[1]	$ 349,389	$ 375,293	$ 424,379	$ 450,239	$ 447,021	$ 6,270,410	$ 8,316,731
Long-term debt[2]	16,852	16,852	16,852	16,852	1,331,784	2,387,963	3,787,155
Interest on long-term debt[2]	249,254	248,269	247,282	246,297	180,410	95,945	1,267,457
Decommissioning obligation[3]	2,557	7,585	7,585	7,585	7,585	766,488	799,385
Finance leases[4]	15,768	15,984	16,092	16,308	16,416	453,681	534,249
Office lease rentals	23,427	21,382	21,117	20,281	17,663	134,881	238,751
Diluent purchases	360,886	21,606	21,547	21,547	17,946	—	443,532
Other commitments[5]	21,456	12,554	10,472	9,441	9,452	49,963	113,338
Total	**$ 1,039,589**	**$ 719,525**	**$ 765,326**	**$ 788,550**	**$ 2,028,277**	**$ 10,159,331**	**$ 15,500,598**

(1) *This represents transportation and storage commitments from 2018 to 2048, including the Access Pipeline TSA, and various pipeline commitments which are awaiting regulatory approval and are not yet in service.*

(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 December 31, 2018.*

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

(4) *This represents the future finance lease payments related to the Stonefell Lease Agreement.*

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

Commitments for various transportation and storage arrangements increased $4.9 billion from December 31, 2017 primarily due to the Corporation's sale of its 50% interest in the Access Pipeline and the resulting TSA to transport blend production and condensate on the Access Pipeline for an initial term of 30 years. The total commitment related to long-term debt decreased $0.9 billion and the total commitment related to interest on long-term debt decreased $0.5 billion from December 31, 2017 primarily due to the partial repayment of the Corporation's senior secured term loan.

b. Contingencies

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

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility in Alberta. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation filed a statement of defense in the first quarter of 2018. The Corporation continues to view this claim, 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.

14. NON-GAAP MEASURES

Certain financial measures in this MD&A including: net marketing activity, funds flow from (used in) operations, adjusted funds flow, operating earnings (loss), 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.

Net Marketing Activity

Net marketing activity is a non-GAAP measure which the Corporation uses to analyze the returns on the sale of third-party crude oil and related products through various marketing and storage arrangements. Net marketing activity represents the Corporation's third-party petroleum sales less the cost of third-party purchased product. Petroleum revenue – third party is disclosed in Note 17 and purchased product and storage – third party is presented in Note 19 to the Consolidated Financial Statements.

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, defense costs related to unsolicited bid, contract cancellation expense, net change in other liabilities, 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.

	Year ended December 31	
($000)	**2018**	**2017**
Net cash provided by (used in) operating activities	**$ 280,032**	$ 317,935
Net change in non-cash operating working capital items	**(111,291)**	24,517
Funds flow from (used in) operations	**168,741**	342,452
Adjustments:		
Realized gain on foreign exchange derivatives(1)	**(35,362)**	—
Defense costs related to unsolicited bid(2)	**19,152**	—
Contract cancellation expense(3)	**—**	18,765
Net change in other liabilities(4)	**3,251**	(9,389)
Payments on onerous contracts	**18,727**	19,569
Decommissioning expenditures	**5,225**	2,403
Adjusted funds flow	**$ 179,734**	$ 373,800

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

(2) *The Corporation incurred costs of $19.2 million in the fourth quarter of 2018 related to Husky Energy Inc.'s unsolicited bid to acquire all of the outstanding shares of the Corporation.*

(3) *During the third quarter of 2017, the Corporation recognized a contract cancellation expense of $18.8 million relating to the termination of a long-term marketing transportation contract that had not yet commenced.*

(4) *Excludes change in long-term cash-settled stock-based compensation liability.*

Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP measure which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating earnings (loss) is defined as net earnings (loss) as reported, excluding unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial instruments, unrealized gains and losses on commodity risk management, realized gains and losses on foreign exchange derivatives not considered part of ordinary continuing operating results, gain on asset dispositions, defense costs related to unsolicited bid, onerous contracts expense, contract cancellation expense, debt extinguishment expense, insurance proceeds and the respective deferred tax impact on these adjustments. Operating earnings (loss) is reconciled to "Net earnings (loss)", the nearest IFRS measure.

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.

($000)	**December 31, 2018**	**December 31, 2017**
Long-term debt	**$ 3,740,150**	$ 4,668,267
Adjustments:		
Current portion of senior secured term loan	**16,852**	15,460
Unamortized financial derivative liability discount	**1,267**	4,242
Unamortized deferred debt discount and debt issue costs	**28,886**	38,499
Total debt	**$ 3,787,155**	$ 4,726,468

15. 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. The following are the critical accounting estimates used in the preparation of the Corporation's consolidated financial statements.

Property, plant and equipment

Field production assets within PP&E are depleted using the unit-of-production method based on estimates of proved bitumen reserves and future costs required to develop those reserves. There are a number of inherent uncertainties associated with estimating reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

Amounts recorded for depreciation of major facilities and equipment and transportation and storage assets are based on management's best estimate of their useful lives and the facilities’ productive capacity. Accordingly, those amounts are subject to measurement uncertainty.

In addition, management is required to make estimates and assumptions and use judgment regarding the timing of when major development projects are ready for their planned use, which also determines when these assets are subject to depletion and depreciation.

Exploration and evaluation assets

The application of the Corporation’s accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined and when technical feasibility and commercial viability have been reached. Estimates and assumptions may change as new information becomes available.

Bitumen reserves

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the cost and timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Corporation expects that over time its reserves estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion and depreciation charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of PP&E carrying amounts.

Provisions

a. Decommissioning provision

   Decommissioning costs are incurred when certain of the Corporation’s tangible long-lived assets are retired. Assumptions are made to estimate the future liability based on current economic factors. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. The impact to net earnings over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. In addition, management exercises judgment to determine the appropriate discount rate at the end of each reporting period. This discount rate, which is a credit-adjusted risk-free rate, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

b. Onerous contracts

   A contract is considered to be onerous when the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be derived from the contract. The determination of when to record a provision for an onerous contract is a complex process that involves management judgment about outcomes of future events and estimates concerning the nature, extent and timing of expected future cash flows and discount rates related to the contract.

Impairments

CGU’s are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGU’s requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures, and the way in which management monitors the Corporation's operations.

The recoverable amounts of CGU's and individual assets have been determined as the higher of the CGU's or the asset's fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGU's.

Stock-based compensation

The fair values of equity-settled and cash-settled share-based compensation plans are estimated using the Black-Scholes options pricing model. These estimates are based on the Corporation's share price and on several assumptions, including the risk-free interest rate, the future forfeiture rate, the expected volatility of the Corporation's share price and the future attainment of performance criteria. Accordingly, these estimates are subject to measurement uncertainty.

Deferred income taxes

Tax regulations and legislation and the interpretations thereof in which the Corporation operates are subject to change. As such, income taxes are subject to measurement uncertainty.

Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date. The periods in which timing differences reverse are impacted by future earnings and capital expenditures. Rates are also affected by changes to tax legislation.

The Corporation also makes interpretations and judgments on the application of tax laws for which the eventual tax determination may be uncertain. To the extent that interpretations change, there may be a significant impact on the consolidated financial statements.

Derivative financial instruments

The estimated fair values of financial assets and liabilities are subject to measurement uncertainty due to their exposure to credit, liquidity and market risks. Furthermore, the Corporation may use derivative instruments to manage commodity price, foreign currency and interest rate exposures. The fair values of these derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows, and discount rates. Management's assumptions rely on external observable market data including quoted forward commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and as such are subject to measurement uncertainty.

Sale and leaseback accounting

During the first quarter of 2018, the Corporation sold its 100% interest in the Stonefell Terminal and management determined that the sale of the Stonefell Terminal and the subsequent lease of the terminal should be accounted for as a sale and leaseback transaction that resulted in a finance lease.

Determining the measurement of a finance lease asset and obligation is a complex process that involves estimates, assumptions and judgments to determine the fair value of leased assets, and estimates on timing and amount of expected future cash flows and discount rates. Any future changes to the estimated discount rate will not impact the carrying values of the finance lease asset and obligation. The leased asset will be subject to property, plant and equipment impairment reviews at subsequent reporting periods.

16. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the year ended December 31, 2018 and December 31, 2017, other than compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($000)		2018		2017
Salaries and short-term employee benefits	**$**	**11,799**	$	7,385
Share-based compensation		**16,850**		9,578
Termination benefits		**3,856**		64
	$	**32,505**	$	17,027

17. OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2018 and December 31, 2017, the Corporation did not have any off-balance sheet arrangements. The Corporation has certain operating or rental lease agreements, as disclosed in the Contractual Obligations and Commitments section of this MD&A, which are entered into in the normal course of operations. Payments of these leases are included as an expense as incurred over the lease term. No asset or liability value had been assigned to these leases as at December 31, 2018 and December 31, 2017.

18. NEW ACCOUNTING STANDARDS

The Corporation has adopted the following standards effective January 1, 2018:

IFRS 15 *Revenue From Contracts With Customers*

The IASB issued IFRS 15 *Revenue From Contracts With Customers*, which was effective January 1, 2018 and replaced IAS 11 *Construction Contracts* and IAS 18 *Revenue* and the related interpretations on revenue recognition. IFRS 15 provides a comprehensive revenue recognition and measurement framework that applies to all contracts with customers. The Corporation adopted IFRS 15 retrospectively as required by the standard on January 1, 2018, and applied a practical expedient whereby completed contracts prior to January 1, 2017 were not assessed. The adoption of this standard did not have a material impact on the Corporation’s consolidated financial statements. Please see the Corporation's Revenue accounting policy in Note 3(r) of the consolidated financial statements.

Impact from change in accounting policy:

Under IFRS 15, revenues from the purchase and sale of proprietary crude oil are recognized on a gross basis as separate performance obligations. In conjunction with the transition to IFRS 15, the presentation of petroleum revenue, net of royalties and purchased product and storage has changed, with no impact on earnings (loss) before income tax, net earnings (loss), comprehensive income (loss), or net cash provided by (used in) operating activities.

The annual impact of these changes in 2017 was as follows:

		Year ended December 31, 2017
Petroleum revenue – proprietary, as previously reported	$	2,168,602
Blend purchases		39,975
Adjusted petroleum revenue – proprietary	**$**	**2,208,577**
Purchased product and storage as previously reported	$	250,681
Blend purchases		39,975
Adjusted purchased product and storage	**$**	**290,656**

Enhanced required disclosures are provided in Notes 17 and 19 of the Corporation's consolidated financial statements.

IFRS 9 *Financial Instruments*

The IASB issued IFRS 9 *Financial Instruments*, which was effective January 1, 2018 and replaced IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The accounting treatment of financial liabilities in IFRS 9 is essentially unchanged from IAS 39, except for financial liabilities designated at fair value through profit or loss, whereby an entity can recognize the portion of the change in fair value related to the change in the entity's own credit risk through other comprehensive income rather than net earnings. The standard also introduces a new expected credit loss impairment model for financial assets. In addition, IFRS 9 incorporates new hedge accounting requirements that more closely align with risk management activities. An amendment to IFRS 9 requires debt modifications to be discounted at the original effective interest rate of the debt rather than a revised effective interest rate as was required under IAS 39. The adoption of this standard did not have a material impact on the Corporation's consolidated financial statements. Please see the Corporation's Financial Instruments accounting policy in Notes 3(c) and 3(m) of the consolidated financial statements.

Impact from change in accounting policy:

The classification of certain financial instruments was impacted by the adoption of IFRS 9. Trade receivables and other are measured at amortized cost under IFRS 9, as the Corporation holds the receivables with the sole intention of collecting contractual cash flows. There were no significant changes to the closing impairment allowance for financial assets determined in accordance with IAS 39 and the expected credit loss allowance determined in accordance with IFRS 9 as at January 1, 2018.

The amendment to IFRS 9 that requires debt modification to be discounted at the original effective interest rate of the debt rather than a revised effective interest rate, as was required under IAS 39, required the Corporation to revise the opening deficit as follows:

		As at January 1, 2018
Increase to net finance expense[1]	$	6,381
Tax effect		(1,722)
Increase to opening deficit	**$**	**4,659**

(1) The increase to net finance expense was the result of a decrease in the unamortized financial derivative liability discount and debt issue costs which resulted in an increase in the carrying value of long-term debt as at January 1, 2018.

IFRS 2 *Share-based Payments*

The IASB issued amendments to IFRS 2 *Share-based Payments*, effective January 1, 2018 relating to classification and measurement of particular share-based payment transactions. The adoption of this revision did not have a material impact on the Corporation's consolidated financial statements.

Accounting standards issued but not yet applied

IFRS 16 *Leases*

In January 2016, the IASB issued IFRS 16 *Leases*, which will replace IAS 17 *Leases*. Under IFRS 16, a single recognition and measurement model will apply for lessees, which will require recognition of lease assets and lease obligations 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 standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach.

IFRS 16 will be adopted by the Corporation on 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 retained earnings and deficit on the transition date and the standard is prospectively applied.

On adoption, the standard is expected to increase the Corporation's assets and liabilities with the recognition of right-of-use assets and corresponding lease liabilities based on the principles of the new standard. The most significant impact on the Corporation of adopting IFRS 16 will be the recognition of right-of-use assets and corresponding lease obligations on long-term leases for office space and marketing storage tank arrangements.

The lease liabilities will be measured at the present value of the remaining lease payments, discounted using the Corporation's incremental borrowing rate as at January 1, 2019. The corresponding right-of-use assets will be measured at the amount equal to the lease liability on January 1, 2019. As a result, there will be 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 will remain unchanged upon transition to IFRS 16. Under the new standard, cash outflows for repayment of the principal portion of the lease liability will be classified as cash flows from financing activities. The interest portion of the lease payments will continue to be classified as cash flows from operating activities.

The 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. However, as an intermediate lessor, on adoption of IFRS 16, the Corporation will reassess 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 will be accounted for as a new finance lease entered into on January 1, 2019.

On initial adoption, the Corporation will use the following practical expedients permitted by the standard to leases previously classified as operating leases applying IAS 17:

- Apply a single discount rate to a portfolio of leases with similar characteristics;
- Rely 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. As a result, the Corporation will adjust the right-of-use asset by the amount of the onerous contracts provision recognized in the consolidated financial statements as at December 31, 2018.

- Account for leases with a remaining term of less than 12 months as at January 1, 2019 as short-term leases.
- Exclude initial direct costs from the measurement of the right-of-use asset as at January 1, 2019.
- Use hindsight when determining the lease term where the contract contains options to extend or terminate the lease.

The Corporation continues to assess and evaluate the impact of the standard on the consolidated financial statements. A process for identifying potential lease contracts has been established and the Corporation has created a process for performing detailed evaluations of its contracts that are potentially leases under IFRS 16. In the first quarter of 2019, these activities will be finalized.

19. 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.

Risks Arising From Construction Activities

Cost and Schedule Risk

Additional phases of development of the Christina Lake Project and the development of the Corporation's other projects may suffer from delays, cancellation, interruptions or increased costs due to many factors, some of which may be beyond the Corporation's control, including:

- engineering, construction and/or procurement performance falling below expected levels of output or efficiency;
- denial or delays in receipt of regulatory approvals, additional requirements imposed by changes in Provincial and Federal laws or non-compliance with conditions imposed by regulatory approvals;
- labour disputes or disruptions, declines in labour productivity or the unavailability of skilled labour;
- increases in the cost of labour and materials; and
- changes in project scope or errors in design.

If any of the above events occur, they could have a material adverse effect on the Corporation's ability to continue to develop the Christina Lake Project, the Corporation's facilities or the Corporation's other future projects and facilities, which would materially adversely affect its business, financial condition and results of operations.

Risks Arising From Operations

Operating Risk

The operation of the Corporation's oil sands properties and projects are and will continue to be subject to the customary hazards associated with recovering, transporting and processing hydrocarbons, such as fires, severe weather, natural disasters (including wildfires), explosions, gaseous leaks, migration of harmful substances, blowouts and spills. A casualty occurrence might result in the loss of equipment or life, as well as injury, property damage or the interruption of the Corporation's operations. The Corporation's insurance may not be sufficient to cover all potential casualties, damages, losses or disruptions. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Operating Results

The Corporation's operating results are affected by many factors. The principal factors, amongst others, which could affect MEG's operating results include:

- a substantial decline in oil, bitumen or electricity prices, due to a lack of infrastructure or otherwise;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher steam-to-oil ratios;
- a lack of access to, or an increase in, the cost of diluent;
- an increase in the cost of natural gas;
- the reliability and maintenance of the Access Pipeline, Stonefell Terminal and MEG's other facilities;
- the need to repair existing horizontal wells, or the need to drill additional horizontal wells;
- the ability and cost to transport bitumen, diluent and bitumen diluent blends, and the cost to dispose of certain by-products;
- increased royalty payments resulting from changes in the regulatory regime;
- a lack of sufficient pipeline or electrical transmission capacity, and the effect that an apportionment may have on MEG’s access to such capacity;
- the cost of labour, materials, services and chemicals used in MEG's operations; and
- the cost of compliance with existing and new regulations.

Labour Risk

The Corporation depends on its management team and other key personnel to run its business and manage the operation of its projects. The loss of any of these individuals could adversely affect the Corporation's operations. Due to the specialized nature of the Corporation's business, the Corporation believes that its future success will also depend upon its ability to continue to attract, retain and motivate highly skilled management, technical, operations and marketing personnel.

Project Development Risks

Reliance on Third Parties

The Christina Lake Project and the Corporation's future projects will depend on the successful operation and the adequate capacities of certain infrastructure owned and operated by third parties or joint ventures with third parties, including:

- pipelines for the transport of natural gas, diluent and blended bitumen;
- power transmission grids supplying and exporting electricity; and
- other third-party transportation infrastructure such as roads, rail, terminals and airstrips.

The failure or lack of any or all of the infrastructure described above will negatively impact the operation of the Christina Lake Project and MEG's future projects, which in turn, may have a material adverse effect on MEG's business, results of operations and financial condition.

Reserves and Resources

There are numerous uncertainties inherent in estimating quantities of in-place bitumen reserves and resources, including many factors beyond the Corporation's control. In general, estimates of economically recoverable bitumen reserves and resources and the future net cash flow therefrom are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the effects of regulation by governmental agencies, and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, the classification of such reserves and resources based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

MEG retained GLJ Petroleum Consultants Ltd. as the Corporation’s independent qualified reserve evaluator to evaluate and prepare a report on the Corporation’s reserves with an effective date of December 31, 2018 and a preparation date of January 11, 2019 (“GLJ Report”). Although third parties have prepared the GLJ Report and other reviews, reports and projections relating to the viability and expected performance of the Christina Lake Project, the Surmont Project, the May River Regional Project and the Growth Properties, the GLJ Report, the reviews, reports and projections and the assumptions on which they are based may not, over time, prove to be accurate. Actual production and cash flow derived from the Corporation's oil sands leases may vary from the GLJ Report and other reviews, reports and projections.

Financing Risk

Significant amounts of capital will be required to develop future phases of the Christina Lake Project, the Surmont Project, the May River Regional Project and the Growth Properties. At present, cash flow from the Corporation's operations is largely dependent on the performance of a single project and a major source of funds available to the Corporation is the issuance of additional equity or debt. Capital requirements are subject to capital market risks, including the availability and cost of capital. There can be no assurance that sufficient capital will be available or be available on acceptable terms or on a timely basis, to fund the Corporation's capital obligations in respect of the development of its projects or any other capital obligations it may have. The Corporation may not generate sufficient cash flow from operations and may not have additional equity or debt available to it in amounts sufficient to enable it to make payments with respect to its indebtedness or to fund its other liquidity needs. In these circumstances, the Corporation may need to refinance all or a portion of its indebtedness on or before maturity. The Corporation may not be able to refinance any of its indebtedness on commercially reasonable terms or at all.

Commodity Price Risk

The Corporation's business, financial condition, results of operations and cash flow are dependent upon the prevailing prices of its bitumen blend, condensate, power and natural gas. Prices of these commodities have historically been extremely volatile and fluctuate significantly in response to regional, national and global supply and demand, government regulations including curtailment orders and other factors beyond the Corporation's control.

Declines in prices received for the Corporation's bitumen blend could materially adversely affect the Corporation's business, financial position, results of operations and cash flow. In addition, any prolonged period of low bitumen blend prices or high natural gas or condensate prices could result in a decision by the Corporation to suspend or reduce production. Any suspension or reduction of production would result in a corresponding decrease in the Corporation's revenues and could materially impact the Corporation's ability to meet its debt service obligations. If over-the-counter derivative structures are employed to mitigate commodity price risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Interest Rate Risk

The Corporation has obtained certain credit facilities to finance a portion of the capital costs of the Christina Lake Project and to fund the Corporation's other development and acquisition activities. Variations in interest rates could result in significant changes to debt service requirements and would affect the financial results of the Corporation. If over-the-counter derivative structures are employed to mitigate interest rate risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Foreign Currency Risk

The Corporation's credit facilities and high yield notes are denominated in U.S. dollars and prices of the Corporation's bitumen blend are generally based on U.S. dollar market prices. Fluctuations in U.S. and Canadian dollar exchange rates may cause a negative impact on revenue, costs and debt service obligations and may have a material adverse impact on the Corporation. If over-the-counter derivative structures are employed to mitigate foreign currency risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Regulatory and Environmental Risk

The oil and gas industry in Canada, including the oil sands industry, operates under Canadian federal, provincial and municipal legislation and regulations. Future development of the Christina Lake Project, the Surmont Project, the May River Regional Project and the Growth Properties is dependent on the Corporation maintaining its current oil sands leases and licences and receiving required regulatory approvals and permits on a timely basis. The Government of Alberta has initiated a process to control cumulative environment effects of industrial development through the Lower Athabasca Regional Plan ("LARP"). While the LARP has not had a significant effect on the Corporation, there can be no assurance that changes to the LARP or future laws or regulations will not adversely impact the Corporation's ability to develop or operate its projects.

The Corporation is committed to meeting its responsibilities to protect the environment and fully comply with all environmental laws and regulations. Alberta regulates emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("GHG"), and Canada's federal government has proposed significant extensions to its GHG regulatory requirements. The direct and indirect costs of the various regulations, existing, proposed and future, may adversely affect MEG's business, operations and financial results. The emission reduction compliance obligations required under existing and future federal and provincial industrial air pollutant and GHG emission reduction targets and requirements, together with emission reduction requirements in future regulatory approvals, may not be technically or economically feasible to implement for MEG's bitumen recovery and cogeneration activities. Any failure to meet MEG's emission reduction compliance obligations may materially adversely affect MEG's business and result in fines, penalties and the suspension of operations.

The International Maritime Organization (“IMO”) is a specialized agency of the United Nations and the main regulatory body for the shipping industry. It is the global standard setting authority for environmental regulation of international shipping. On January 1, 2020 the global limit for sulphur in fuel used onboard ships will decrease from the current upper limit of 3.5 weight percent to 0.5 weight percent. Due to the sulphur content in heavy oils, such as bitumen, processing by complex refineries is required to meet the new IMO sulphur standards and the availability of refining capacity for bitumen may become scarce after the new limit comes into effect. The IMO sulphur regulation has the potential to materially adversely impact the crude marketing of bitumen and contribute to an increased widening of the light to heavy crude oil differential.

Alberta Climate Leadership Plan

For the 2017 compliance year, the Corporation was subject to the Specified Gas Emitters Regulation (the "SGER"), which imposes greenhouse gas emissions intensity limits and reduction requirements for owners of facilities that emit 100,000 tonnes or more per year of greenhouse gas. In December 2017, the Alberta government released the Carbon Competitiveness Incentive Regulation (the “CCIR”), which came into force on January 1, 2018. The CCIR replaces the SGER for compliance years 2018 and thereafter. Various elements of the SGER are included in the CCIR, as the CCIR remains an emissions intensity-based regime requiring large emitters to reduce their emissions intensity below a prescribed level, or otherwise achieve this through a true-up obligation whereby credits can be applied against such required level, together with or as an alternative to physical abatement, with penalties for failure to achieve compliance. However, the CCIR has fundamental differences with SGER as the facility specific baselines in the SGER have now largely been replaced in the CCIR with product specific benchmarks.

There are four compliance options for facilities that are subject to the CCIR: (i) improve emissions intensity at the facility; (ii) purchase or use banked emission performance credits (“EPCs”); (iii) purchase emission offsets in the open market, which are generated from Alberta based projects; and/or (iv) purchase fund credits by contributing to the Climate Change and Emissions Management Fund ("Fund") run by the Alberta government. Currently the contribution costs to the Fund are set at $30 per tonne although this is subject to change by Ministerial order. Under the CCIR there are no limits on purchasing fund credits to meet a facility’s true up obligation; however, the CCIR includes limits on the use of EPCs and emission offsets for compliance purposes, and adds expiry periods for EPCs and emission offsets according to the vintage year.

In November 2015, the Government of Alberta announced its climate leadership plan (the "Plan") and released to the public the climate leadership report to the Minister of Environment and Parks that it commissioned from the Climate Change Advisory Panel and on which the Plan is largely based. The Plan highlights four key strategies that the Government of Alberta is implementing to address climate change: (i) the complete phase-out of coal-fired sources of electricity by 2030; (ii) an Alberta economy-wide price on greenhouse gas emissions of $30 per tonne; (iii) capping oil sands emissions to a province-wide total of 100 megatonnes per year (compared to current emissions of approximately 70 megatonnes per year), with certain exceptions for cogeneration power sources and new upgrading capacity; and (iv) reducing methane emissions from oil and gas activities by 45% by 2025. Certain details regarding how the Plan will be implemented, for example, the carbon levy under the *Climate Leadership Act,* the CCIR and the Methane Emissions Reduction under the Environmental Protection and Enhancement Act, have been released. The *Oil Sands Emissions Limit Act* has been enacted but it does not obligate oil sands producers until a regulatory system is designed and implemented under the regulations. Certain details regarding how the Plan will be implemented have not been released.

The Climate Leadership Act came into force on January 1, 2017 and establishes an Alberta carbon pricing regime in the form of a carbon levy on various types of fuel. Under the Climate Leadership Act, facilities subject to the SGER and the CCIR are exempt from the carbon levy.

No assurance can be given that environmental laws and regulations, including the implementation of the Plan, will not result in a curtailment of the Corporation's production or a material increase in the Corporation's costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's results of operations, financial condition and prospects. The Corporation believes that it is reasonably likely that the trend towards stricter standards in environmental legislation will continue and anticipates that capital and operating costs may increase as a result of more stringent environmental laws. A legislated cap on oil sands greenhouse gas emissions could significantly reduce the value of the Corporation's assets.

The Paris Agreement

Canada and 195 other countries that are members of the United Nations Framework Convention on Climate Change met in Paris, France in December 2015, and signed the Paris Agreement on climate change. The stated objective of the Paris Agreement is to hold "the increase in global average temperature to well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius." Signatory countries agreed to meet every five years to review their individual progress on greenhouse gas emissions reductions and to consider amendments to individual country targets, which are not legally binding. Canada is required to report and monitor its greenhouse gas emissions, though details of how such reporting and monitoring will take place have yet to be determined. Additionally, the Paris Agreement contemplates that, by 2020, the parties will develop a new market-based mechanism related to carbon trading. It is expected that this mechanism will largely be based on the best practices and lessons learned from the Kyoto Protocol. The Government of Canada has stated that it will develop and announce a Canada-wide approach to implementing the Paris Agreement.

In December 2016, the Government of Canada adopted the “Pan-Canadian Framework on Clean Growth and Climate change (the "Framework”) in response to the Paris Agreement. Under the Framework, the federal government introduced a carbon pricing program that includes, at a minimum, a floor price on carbon emissions of $10 per tonne in 2018, rising by $10 per tonne each year to $50 per tonne in 2022. The Framework allows provinces to implement either a carbon tax or use a broad market based mechanism and includes a federal backstop in the event jurisdictions do not meet the floor carbon price. The federal Greenhouse Gas Pollution Pricing Act ("GGPPA") came into force on June 21, 2018 and is similar in structure to Alberta's current approach to carbon pricing, in that it includes a levy on fossil fuels and an output-based pricing system for industrial facilities. The GGPPA applies, in whole or in part, in provinces that voluntarily adopt the federal standard or that do not have a carbon pricing system in place that meets the federal standard by January 1, 2019. On October 23, 2018 the federal government confirmed that Alberta's current approach to carbon pricing is equivalent to the federal standard and as a result the GGPPA currently does not apply in Alberta.

Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil sands producers. The Corporation is unable to predict the impact of emissions reduction legislation on the Corporation and it is possible that such legislation may have a material adverse effect on the Corporation's financial condition, results of operations and prospects.

Royalty Risk

The Corporation's revenue and expenses will be directly affected by the royalty regime applicable to its oil sands development. The Government of Alberta implemented a new oil and gas royalty regime effective January 1, 2009 through which the royalties for bitumen are linked to price and production levels. The royalty regime applies to both new and existing oil sands projects.

Under the royalty regime, the Government of Alberta increased its royalty share from oil sands development by introducing price-sensitive formulas applied both before and after specified allowed costs have been recovered.

The Government of Alberta has publicly indicated that it intends for the revised royalty regime to be further reviewed and revised from time to time. There can be no assurances that the Government of Alberta or the Government of Canada will not adopt new royalty regimes which may render the Corporation's projects uneconomic or otherwise adversely affect its business, financial condition or results of operations.

On January 29, 2016, the Alberta government finalized results of a royalty review which commenced in September 2015 and announced that the current structure and royalty rates for oil sands will generally remain unchanged.

There can be no assurances that the government of Alberta will not adopt new royalty regimes which may render the Corporation's projects uneconomic or adversely affect its results of operations, financial condition or prospects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments or the Corporation's operations uneconomic and could make it more difficult to service and repay the Corporation's debt. Any material increase in royalties could also materially reduce the value of the Corporation's assets.

Lease Expiries Risk

Certain of MEG's oil sands leases may expire and MEG may be required to surrender lands to the Province of Alberta. The initial term for MEG's oil sands leases, some of which began in or subsequent to 1996, is 15 years. At the conclusion of this initial term, each oil sands lease may be continued if it meets certain criteria related to the extent to which MEG has evaluated the oil sands resource covered by the lease. Continued leases currently have indefinite terms and application for continuation may be made during the last year of the term of the lease or at any time during the lease with the consent of the Minister.

In view of the potentially changing tenure environment, MEG is actively evaluating all of its oil sands leases to determine the best continuation approach. In 2018, 9 sections on 3 of MEG's oil sand leases expired in MEG's Growth Properties. No reserves or contingent resources were associated with these lands. In 2018, MEG received indefinite continuations on 31 leases with 2018 and 2019 expiry dates. With these extensions and continuations, none of MEG's oil sands leases are scheduled to expire in 2019 or 2020.

Certain oil sands leases located in MEG's Growth Properties (those outside of the Christina Lake, Surmont and May River Regional Projects) are scheduled to expire in 2021 and beyond. As further described in the AIF, MEG is actively working on a lease continuation strategy for these lands in the context of the caribou extensions and the evolving lease tenure regulations.

The Corporation cannot predict the outcome of the lease tenure review and the resulting impact on MEG's oil sands leases. In order to assist lessees in adapting to the changing tenure environment, Alberta Energy has relaxed the minimum level of evaluation while such lease tenure review is ongoing and also provided extensions to lease terms. In 2018, Alberta Energy offered the ability for lessees to apply for further lease extensions to March 31, 2021 for leases that fall within designated caribou ranges. MEG received applicable lease expiry extensions to March 31, 2021 on 27 oil sands leases located at Surmont and the Growth Properties.

Third Party Risks

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the Regional Municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the Christina Lake Project, MEG's other projects and most of the other oil sands operations in Alberta are located. Such claims and other similar claims that may be initiated, if successful, could have a significant adverse effect on MEG and the Christina Lake Project and MEG's other projects.

20. 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. The CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the Corporation and have concluded that the Corporation's disclosure controls and procedures were effective at December 31, 2018 for the foregoing purposes.

21. 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's and CFO's evaluation concluded that internal controls over financial reporting were effective as of December 31, 2018.

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.

22. 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

23. 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; 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: net marketing activity, funds flow from (used in) operations, adjusted funds flow, operating earnings (loss), 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.

24. 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.

25. QUARTERLY SUMMARIES

	2018				2017			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL ($000 unless specified)								
Net earnings (loss)	**(199,360)**	118,160	(178,570)	140,573	(23,779)	83,885	104,282	1,588
Per share, diluted	**(0.67)**	0.39	(0.61)	0.47	(0.08)	0.28	0.35	0.01
Operating earnings (loss)	**(118,162)**	(19,011)	(70,174)	(18,015)	44,055	(42,571)	(35,656)	(79,354)
Per share, diluted	**(0.40)**	(0.06)	(0.24)	(0.06)	0.15	(0.14)	(0.12)	(0.29)
Adjusted funds flow	**(37,562)**	115,742	18,393	83,157	192,178	83,352	55,095	43,175
Per share, diluted	**(0.13)**	0.39	0.06	0.28	0.65	0.28	0.19	0.16
Cash capital investment	**144,006**	144,508	182,567	147,739	163,337	103,173	158,474	77,770
Cash and cash equivalents	**317,704**	372,550	563,969	675,116	463,531	397,598	512,424	548,981
Working capital	**289,755**	274,344	211,045	445,792	313,025	350,067	445,463	537,427
Long-term debt	**3,740,150**	3,543,587	3,606,765	3,542,763	4,668,267	4,635,740	4,813,092	4,944,741
Shareholders' equity	**3,885,538**	4,068,048	3,945,782	4,112,531	3,964,113	3,981,750	3,898,054	3,792,818
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**58.81**	69.50	67.88	62.87	55.40	48.21	48.29	51.91
C$ equivalent of 1US$ - average	**1.3215**	1.3070	1.2911	1.2651	1.2717	1.2524	1.3449	1.3230
Differential – WTI:WCS (C$/bbl)	**52.11**	29.08	24.88	30.72	15.59	12.45	14.97	19.29
Differential – WTI:WCS (%)	**67.0%**	32.0%	28.4%	38.6%	22.1%	20.6%	23.0%	28.1%
Natural gas – AECO ($/mcf)	**1.70**	1.28	1.26	2.26	1.84	1.58	2.81	2.91
OPERATIONAL ($/bbl unless specified)								
Blend sales - proprietary – bbls/d	**127,427**	132,461	109,984	145,189	135,533	114,789	110,695	111,489
Blend purchases - bbls/d	**(677)**	(1,638)	(1,747)	(9,488)	—	(7,189)	(2,073)	—
Diluent usage – bbls/d	**(38,467)**	(36,967)	(33,819)	(44,093)	(40,992)	(30,787)	(34,506)	(36,786)
Bitumen sales – bbls/d	**88,283**	93,856	74,418	91,608	94,541	76,813	74,116	74,703
Bitumen production – bbls/d	**87,582**	98,751	71,325	93,207	90,228	83,008	72,448	77,245
Steam-oil ratio (SOR)	**2.2**	2.2	2.2	2.2	2.2	2.3	2.3	2.4
Blend sales price	**36.59**	63.67	62.42	51.50	57.01	47.93	49.86	48.77
Bitumen realization	**13.90**	49.58	47.20	35.31	48.30	39.89	39.66	37.93
Transportation – net	**(10.28)**	(9.11)	(8.28)	(5.99)	(7.00)	(7.08)	(6.91)	(6.54)
Royalties	**(0.15)**	(2.01)	(1.64)	(1.03)	(0.84)	(0.53)	(0.87)	(0.85)
Operating costs – non-energy	**(4.25)**	(4.38)	(5.47)	(4.55)	(4.53)	(4.57)	(4.23)	(5.20)
Operating costs – energy	**(1.98)**	(1.50)	(1.79)	(2.64)	(2.03)	(2.26)	(3.76)	(4.18)
Power revenue	**1.68**	1.54	1.62	1.21	0.70	0.83	0.57	0.95
Realized gain (loss) on commodity risk management	**6.81**	(10.16)	(13.11)	(2.15)	(0.77)	0.56	(1.50)	0.22
Cash operating netback	**5.73**	23.96	18.53	20.16	33.83	26.84	22.96	22.33
Power sales price (C$/MWh)	**55.38**	51.53	51.02	35.50	21.37	23.29	18.27	22.42
Power sales (MW/h)	**111**	117	98	130	129	115	97	131
Depletion and depreciation rate per bbl of production	**13.79**	13.85	16.08	13.22	14.26	16.86	16.93	16.81
COMMON SHARES								
Shares outstanding, end of period (000)	**296,841**	296,813	296,751	294,105	294,104	294,079	294,047	293,282
Volume traded (000)	**151,873**	128,363	166,016	89,721	76,531	70,216	98,795	123,445
Common share price ($)								
High	**11.70**	11.51	11.24	6.43	6.82	5.79	7.27	9.83
Low	**7.25**	6.78	4.49	4.28	4.54	3.28	3.63	5.84
Close (end of period)	**7.71**	8.03	10.96	4.55	5.14	5.49	3.81	6.74

26. ANNUAL SUMMARIES

Unaudited	2018	2017	2016	2015	2014	2013
FINANCIAL ($000 unless specified)						
Net earnings (loss)	**(119,197)**	165,976	(428,726)	(1,169,671)	(105,538)	(166,405)
Per share, diluted	**(0.40)**	0.57	(1.90)	(5.21)	(0.47)	(0.75)
Operating earnings (loss)	**(225,360)**	(113,524)	(455,098)	(374,374)	247,353	386
Per share, diluted	**(0.76)**	(0.39)	(2.01)	(1.67)	1.10	0.00
Adjusted funds flow	**179,734**	373,800	(61,607)	49,460	791,458	253,424
Per share, diluted	**0.60**	1.29	(0.27)	0.22	3.52	1.13
Cash capital investment	**618,820**	502,754	137,245	257,178	1,237,539	2,111,824
Cash and cash equivalents	**317,704**	463,531	156,230	408,213	656,097	1,179,072
Working capital	**289,755**	313,025	96,442	363,038	525,534	1,045,606
Long-term debt	**3,740,150**	4,668,267	5,053,239	5,190,363	4,350,421	3,990,748
Shareholders' equity	**3,885,538**	3,964,113	3,286,776	3,677,867	4,768,235	4,788,430
BUSINESS ENVIRONMENT						
WTI (US$/bbl)	**64.77**	50.95	43.33	48.80	93.00	97.96
C$ equivalent of 1US$ - average	**1.2962**	1.2980	1.3256	1.2788	1.1047	1.0296
Differential – WTI:WCS (C$/bbl)	**34.10**	15.55	18.35	17.29	21.63	25.89
Differential – WTI:WCS (%)	**40.6%**	23.5%	31.9%	27.7%	21.1%	25.7%
Natural gas – AECO ($/mcf)	**1.62**	2.29	2.25	2.71	4.50	3.16
OPERATIONAL ($/bbl unless specified)						
Blend sales - proprietary – bbls/d	**128,727**	118,183	116,585	117,132	97,335	48,742
Blend purchases - bbls/d	**(3,359)**	(2,328)	—	—	—	—
Diluent usage – bbls/d	**(38,317)**	(35,766)	(36,159)	(36,167)	(30,092)	(15,027)
Bitumen sales – bbls/d	**87,051**	80,089	80,426	80,965	67,243	33,715
Bitumen production – bbls/d	**87,731**	80,774	81,245	80,025	71,186	35,317
Steam-oil ratio (SOR)	**2.2**	2.3	2.3	2.5	2.5	2.6
Blend sales price	**53.26**	51.20	38.11	42.08	76.05	67.88
Bitumen realization	**36.25**	41.89	27.79	30.63	62.67	49.28
Transportation – net	**(8.42)**	(6.89)	(6.46)	(4.82)	(1.38)	(0.26)
Royalties	**(1.20)**	(0.77)	(0.29)	(0.70)	(4.36)	(3.14)
Operating costs – non-energy	**(4.62)**	(4.62)	(5.62)	(6.54)	(8.02)	(9.00)
Operating costs – energy	**(1.98)**	(2.98)	(3.01)	(3.84)	(6.30)	(4.62)
Power revenue	**1.51**	0.76	0.64	0.99	2.26	3.61
Realized gain (loss) on commodity risk	**(4.37)**	(0.39)	0.08	—	—	—
Cash operating netback	**17.17**	27.00	13.13	15.72	44.87	35.87
Power sales price (C$/MWh)	**47.87**	21.49	18.74	27.48	48.83	76.23
Power sales (MW/h)	**114**	118	115	121	129	67
Depletion and depreciation rate per bbl of production	**14.12**	16.13	16.81	16.00	14.57	14.67
COMMON SHARES						
Shares outstanding, end of year (000)	**296,841**	294,104	226,467	224,997	223,847	222,507
Volume traded (000)	**535,973**	368,987	566,751	248,316	227,538	134,087
Common share price ($)						
High	**11.70**	9.83	9.79	25.20	41.29	36.69
Low	**4.28**	3.28	3.46	7.33	13.30	25.50
Close (end of year)	**7.71**	5.14	9.23	8.02	19.55	30.61