# Report to Shareholders for the year ended December 31, 2018

(All financial figures are expressed in Canadian dollars ($ or C$) unless otherwise noted)

"While 2018 saw strong operational successes, the challenging commodity price environment, particularly during the fourth quarter, hindered bitumen realizations and adjusted funds flow for the company. Notwithstanding commodity price volatility and significant organizational changes, MEG's solid foundation remains intact. Our world class 100,000 barrels per day operations tied to an exceptional resource base, our dedicated workforce, and our well-structured balance sheet, enables us to move forward with a renewed business focus," says Derek Evans, President and Chief Executive Officer. "In the current commodity price environment, financial discipline and balance sheet protection takes precedence over production growth. MEG's 2019 base capital investment plan of $200 million signals our commitment to living within our means, while retaining the flexibility to pursue debt reduction and advance profitable development in line with market conditions to realize long-term sustainable returns going forward. Based on current strip pricing, we expect our Net Debt to LTM EBITDA to come into the range of 3.50x to 3.75x by the end of 2019."

Operational and financial highlights in 2018 include:

- The appointment of Derek Evans to Chief Executive Officer in August 2018;
- Closing of the sale of MEG's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of $1.52 billion and other consideration of $90 million, and the repayment of $1.2 billion of the Corporation's senior secured term loan in the first quarter of 2018;
- Record bitumen production volumes of 87,731 barrels per day (bbls/d) and a record low steam-oil-ratio (SOR) of 2.19, compared to 2.30 in 2017;
- Record low per barrel net operating costs of $5.09 per barrel, including low non-energy operating costs of $4.62 per barrel, compared to guidance of $4.50 to $5.00 per barrel;
- Total cash capital investment of $619 million, $51 million below the revised guidance, primarily focused on advancing the Phase 2B brownfield expansion and the successful application of MEG's proprietary reservoir enhancement technology eMSAGP on Phase 2B, increasing overall production capacity from 80,000 to 100,000 bbls/d;
- Adjusted funds flow of $180 million or $0.60 per share, impacted by the significant widening of the WTI:WCS differential during the fourth quarter; and
- Year-end cash and cash equivalents of $318 million, which along with expected adjusted funds flow, will more than enable MEG to fully fund its 2019 capital program.

"In response to the challenging, short-term volatility in commodity prices during the fourth quarter, the company preserved its liquidity by restricting the number of barrels it sold into an unprofitable market environment. We accomplished this by moving forward a portion of our 2019 turnaround into November, voluntarily reducing production during the month of December, and ramping up the use of rail to sell our product into higher-priced markets," says Derek Evans. "Since January, in conjunction with the provincially mandated curtailments for the industry and the increase in overall crude by rail exports, commodity prices have improved significantly, and our barrels have returned to profitability. Our objective of generating free cash flow in 2019 remains intact."

Bitumen production in the fourth quarter of 2018 averaged 87,582 bbls/d as a result of the Corporation's direct response to mitigate the effects of the significant widening of the WTI:WCS differential by voluntarily curtailing production. 2018 Bitumen production averaged 87,731 bbls/d compared to 80,774 bbls/d in 2017. The increase in average production volumes for the year ended December 31, 2018 was primarily due to the efficiency gains achieved from eMSAGP at the Christina Lake Project.

Net operating costs for the fourth quarter of 2018 averaged $4.55 per barrel, supported by near-record low non-energy operating costs of $4.25 per barrel. The Corporation realized record low net operating costs of $5.09 per barrel in 2018, 26% below the record of $6.84 per barrel achieved in the prior year. The decrease in net operating costs was primarily the result of a per barrel decrease in energy operating costs and an increase in per barrel power revenue. Non-energy operating costs averaged $4.62 per barrel for each of the years ended December 31, 2018, and 2017.

**Pricing and Market Access**

The fourth quarter of 2018 was a challenging period for Canadian oil producers due to a rapid decline in Canadian heavy crude oil prices. MEG's blend sales price of $36.59 per barrel in the fourth quarter of 2018 was negatively impacted by historically wide WTI:WCS differentials of US$39.43 per barrel. In comparison, MEG's blend sales price was $57.01 per barrel in the fourth quarter of 2017 with a WTI:WCS differential of US$12.26 per barrel. The Corporation partially mitigated the wider differentials during the fourth quarter of 2018 by selling 33% of blend volumes into the higher-priced U.S. Gulf Coast market via the Flanagan South/Seaway pipelines and rail. On an annual basis, in contrast to the 27% increase in WTI benchmark price,  MEG's blend sales price increased by 4% to average $53.26 per barrel in 2018 compared to $51.20 per barrel in 2017 due to the widening WTI:WCS differential.

MEG's bitumen realization during the fourth quarter averaged $13.90 per barrel, as a result of the significant widening of the WTI:WCS differential negatively impacting both the blend sales price and the cost recovered on the Corporation's diluent purchases. The increase in average condensate benchmark prices and the timing of inventory purchases negatively impacted diluent expense during the fourth quarter. Bitumen realization averaged $36.25 per barrel in 2018, compared to $41.89 per barrel in 2017. The Corporation's cost of diluent averaged $89.28 per barrel in the fourth quarter and $91.60 per barrel in 2018, compared to $72.32 per barrel of diluent in 2017, primarily due to an increase in average condensate benchmark pricing.

During the fourth quarter of 2018 MEG doubled its rail volumes from the prior quarter to 14,700 bbls/d, 56% of which were delivered to the U.S. Gulf Coast. The Corporation estimates rail volumes to average 20,000 bbls/d in the first quarter, increasing to 30,000 bbls/d by the third quarter of 2019. As a mechanism to clear barrels during periods of high pipeline apportionment and reduce exposure to the post-apportionment market, the use of rail enables MEG to maximize the price received on its barrels until additional egress capacity from Western Canada is secured.

Transportation costs averaged $10.28 per barrel during the fourth quarter of 2018, compared to $8.42 per barrel and $6.89 per barrel for full-year 2018 and 2017 respectively. The increase in costs on a per barrel basis is primarily the result of incremental costs associated with the Access Transportation Services Agreement that was put in place after the sale of MEG's 50% interest in the pipeline and its 100% interest in the Stonefell Terminal on March 22, 2018, as well as additional costs associated with increased volumes transported by rail to the U.S Gulf Coast.

"The production curtailments put in place by the Alberta government since January have helped to strengthen the price we receive for our products. With nearly one-third of our blend sales exposed to the higher-price Gulf Coast market in 2019, we anticipate our blend sales realization to be above the WCS benchmark for the full year," says Evans. "By mid-2020, we expect to double the number of barrels we will sell into the U.S. Gulf Coast as our commitment on Flanagan South/ Seaway increases from 50,000 to 100,000 bbls/d."

**Capital Investment**

Total cash capital investment in 2018 totaled $619 million, compared to $503 million in 2017 and the previously revised guidance of $670 million announced in August 2018. Capital investment in 2018 was primarily directed towards completing the rollout of eMSAGP on Christina Lake Phase 2B, advancement of the Corporation's Phase 2B Brownfield expansion and sustaining and maintenance activities.

**Adjusted Funds Flow and Net Earnings**

The Corporation realized a cash operating netback of $5.73 per barrel in fourth quarter of 2018 as a direct result of the WTI:WCS differential which negatively impacted bitumen realizations, partially offset by a realized gain on commodity risk management contracts of $6.81 per barrel. Cash operating netback for 2018 averaged $17.17 per barrel compared to $27.00 per barrel for 2017, impacted by similar factors.

Adjusted funds flow was impacted by the same primary factors as cash operating netback, resulting in realized negative adjusted funds flow of $38 million, or $(0.13) per share in the fourth quarter of 2018. Adjusted funds flow for the full-year 2018 was $180 million, or $0.60 per share, compared to $374 million for 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 bitumen realization year-over-year, combined with realized losses on commodity risk management contracts during 2018.

The Corporation recognized a net loss of $199 million in the fourth quarter of 2018, which in addition to the impact of depressed prices, reflects a net foreign exchange loss of $198 million, partially offset by a gain on commodity risk management contracts of $228 million. The Corporation recognized a net loss of $119 million for the year ended December 31, 2018 compared to net earnings of $166 million for the year ended December 31, 2017. The net loss in 2018 included a net foreign exchange loss of $311 million, offset by a gain on commodity risk management contracts of $23 million and a gain on asset dispositions of $325 million, primarily related to the sale of the Corporation's 50% interest in the Access Pipeline.

**Outlook**

Announced in January, MEG's 2019 capital investment plan includes a base capital budget of $200 million, designed to sustain production capability at 100,000 bbls/d and advance growth projects beyond 2019. While MEG has the ability to average 100,000 bbls/d of production, the Corporation's 2019 production guidance of 90,000 to 92,000 bbls/d reflects the impact of the Alberta Government's mandated production curtailment, with the assumption that it eases throughout the year. Subject to market conditions, the Corporation has the option to layer in discretionary capital spend of $75 million in 2H19 to support highly economic production growth to 113,000 bbls/d by early 2021.

General and administrative (G&A) expense averaged $2.58 per barrel in 2018, a 12% decrease from $2.94 per barrel in 2017. To align with lower levels of capital spending and to further optimize operational efficiencies, the Corporation made the difficult decision to reduce its staffing levels in February. Based on the current production guidance, MEG anticipates 2019 G&A costs of $1.95 to $2.05 per barrel.

**Board Renewal Update**

MEG's Board renewal process is well underway. Korn Ferry has been engaged and is actively searching for three new board members with the necessary skillsets and experience, that would stand for election at the Corporation's upcoming annual general meeting in June 2019.

**Unsuccessful Take-Over Offer from Husky**

On October 2, 2018, Husky Energy Inc. made an unsolicited offer directly to MEG shareholders to acquire all of the issued and outstanding common shares of the Corporation. At expiry on January 16, 2019, the offer did not meet minimum tender conditions and Husky chose not to extend its offer.

**Forward-Looking Information**

This 2018 report contains forward-looking information and financial measures that are not defined by International Financial Reporting Standards ("IFRS") and should be read in conjunction with the "Forward-Looking Information" and "Non-GAAP Financial Measures" contained within the Advisory sections of this years Management Discussion and Analysis and Press Release.

*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.*

**MD&A - Table of Contents**

## 1. BUSINESS DESCRIPTION

MEG is an oil sands company focused on sustainable *in situ* oil sands development and production in the southern Athabasca oil sands region of Alberta, Canada. MEG is actively developing enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods. 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.

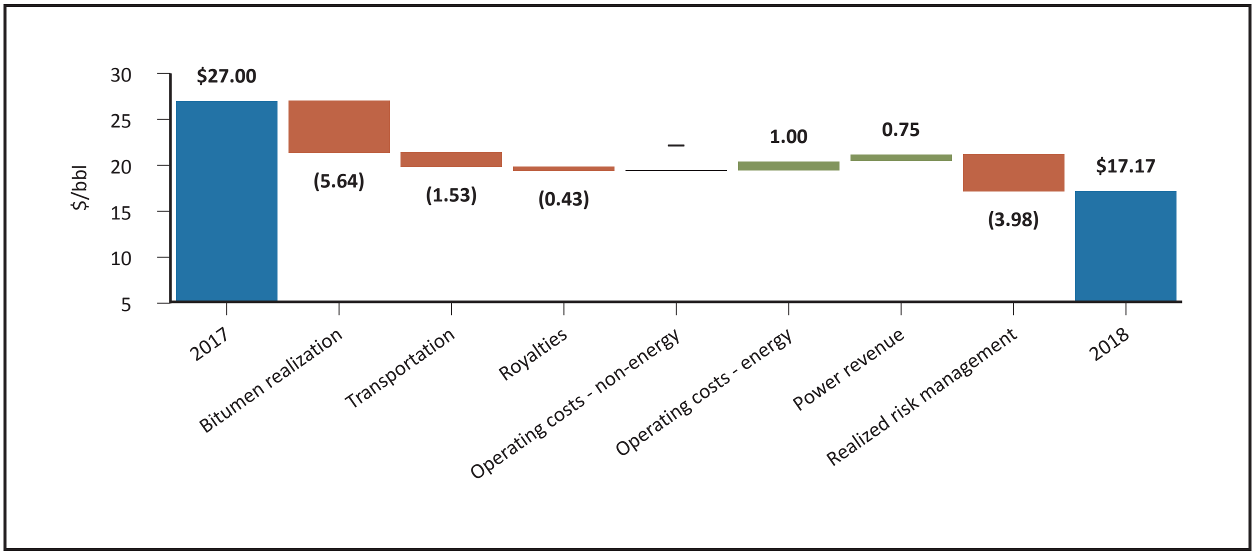
### Cash Operating Netback

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.

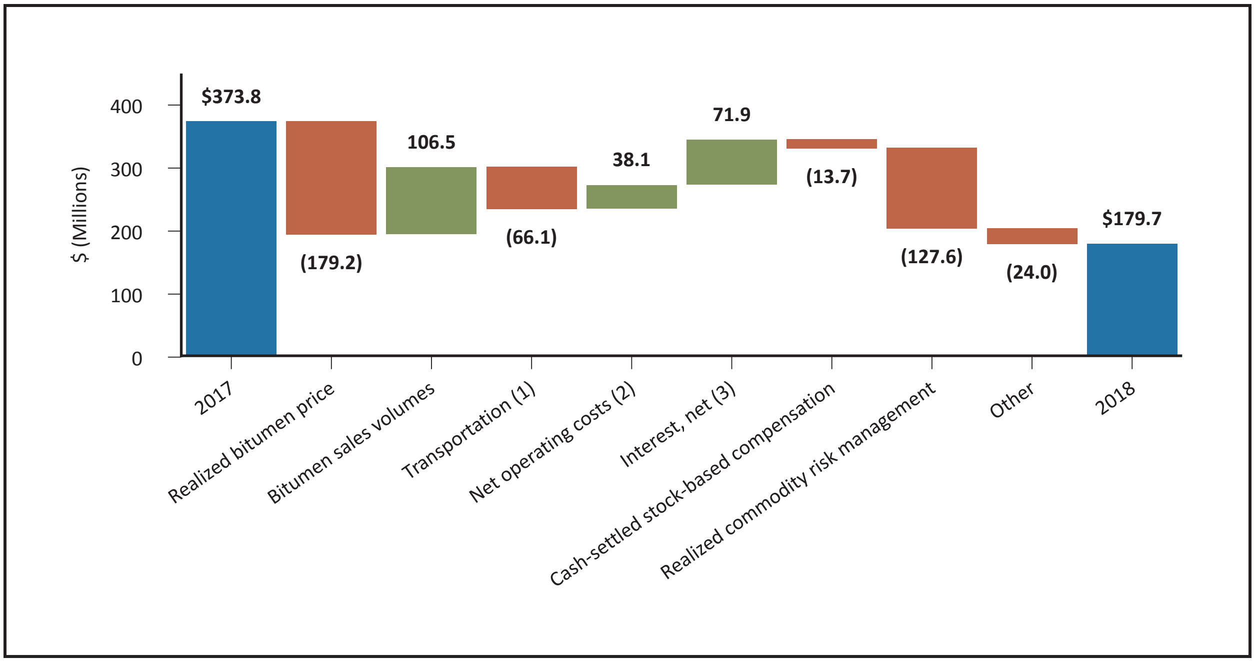
**Power revenue**

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$ | | | | |
| 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 |

## REPORT OF MANAGEMENT

## MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

The accompanying consolidated financial statements of MEG Energy Corp. (the "Corporation") are the responsibility of Management. The consolidated financial statements have been presented and prepared within acceptable limits of materiality by Management in Canadian dollars in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and include certain estimates that reflect Management's best judgments. Financial information contained throughout the Annual Report is consistent with these consolidated financial statements.

The Corporation maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Corporation's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that the Corporation's internal controls over financial reporting were effective as of December 31, 2018.

The Corporation's Board of Directors has approved the consolidated financial statements. The Board of Directors fulfills its responsibility regarding the consolidated financial statements mainly through its Audit Committee, which is made up of three independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation. The Audit Committee meets with Management and the independent auditors at least on a quarterly basis to review and approve interim consolidated financial statements and management's discussion and analysis prior to their release as well as annually to review the annual consolidated financial statements and management's discussion and analysis and recommend their approval to the Board of Directors.

PricewaterhouseCoopers LLP, an independent firm of auditors, has been engaged, as approved by a vote of the shareholders at the Corporation's most recent Annual General Meeting, to audit and provide their independent audit opinion on the Corporation's consolidated financial statements as at and for the year ended December 31, 2018. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

| | |
|---|---|
| /s/ Derek Evans | /s/ Eric L. Toews |
| Derek Evans<br>President and Chief Executive Officer | Eric L. Toews, CPA, CA<br>Chief Financial Officer |

March 7, 2019

# Independent auditor's report

To the Shareholders of MEG Energy Corp.

## Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of MEG Energy Corp. and its subsidiary (together, the "Corporation") as at December 31, 2018 and 2017, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

**What we have audited**
The Corporation's consolidated financial statements comprise:

- the consolidated balance sheets as at December 31, 2018 and 2017;
- the consolidated statements of earnings (loss) and comprehensive income (loss) for the years then ended;
- the consolidated statements of changes in shareholders' equity for the years then ended;
- the consolidated statements of cash flow for the years then ended; and
- the notes to the consolidated financial statements, which include a summary of significant accounting policies.

## Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

**Independence**
We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

## Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis, which we obtained prior to the date of this auditor's report and the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report, which is expected to be made available to us after that date.

*PricewaterhouseCoopers LLP*
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*T: +1 403 509 7500, F: +1 403 781 1825*

Our opinion on the consolidated financial statements does not cover the other information and we do not and will not express an opinion or any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed on the other information that we obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard. When we read the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report, if we conclude that there is a material misstatement therein, we are required to communicate the matter to those charged with governance.

## *Responsibilities of management and those charged with governance for the consolidated financial statements*

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Corporation's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

## *Auditor's responsibilities for the audit of the consolidated financial statements*

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Corporation to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this independent auditor's report is Jason Grodziski.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
March 7, 2019

**Consolidated Balance Sheet**
**(Expressed in thousands of Canadian dollars)**

| As at December 31 | Note | | 2018 | | 2017 |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| Current assets | | | | | |
| Cash and cash equivalents | 25 | $ | 317,704 | $ | 463,531 |
| Trade receivables and other | 5 | | 218,203 | | 289,104 |
| Inventories | 6 | | 97,514 | | 85,850 |
| Commodity risk management | 27 | | 122,658 | | — |
| | | | 756,079 | | 838,485 |
| Non-current assets | | | | | |
| Property, plant and equipment | 7 | | 6,645,224 | | 7,634,399 |
| Exploration and evaluation assets | 8 | | 550,020 | | 548,828 |
| Intangible assets | 9 | | 10,948 | | 13,037 |
| Other assets | 10 | | 210,628 | | 145,732 |
| Deferred income tax asset | 14 | | 236,578 | | 182,871 |
| **Total assets** | | $ | 8,409,477 | $ | 9,363,352 |
| **Liabilities** | | | | | |
| Current liabilities | | | | | |
| Accounts payable and accrued liabilities | 11 | $ | 426,353 | $ | 413,905 |
| Current portion of long-term debt | 12 | | 16,852 | | 15,460 |
| Current portion of provisions and other liabilities | 13 | | 17,058 | | 27,446 |
| Commodity risk management | 27 | | 6,061 | | 68,649 |
| | | | 466,324 | | 525,460 |
| Non-current liabilities | | | | | |
| Long-term debt | 12 | | 3,740,150 | | 4,668,267 |
| Provisions and other liabilities | 13 | | 293,817 | | 205,512 |
| Commodity risk management | 27 | | 23,648 | | — |
| Total liabilities | | | 4,523,939 | | 5,399,239 |
| **Shareholders' equity** | | | | | |
| Share capital | 15 | | 5,427,023 | | 5,403,978 |
| Contributed surplus | | | 170,173 | | 166,636 |
| Deficit | | | (1,750,653) | | (1,629,091) |
| Accumulated other comprehensive income | | | 38,995 | | 22,590 |
| Total shareholders' equity | | | 3,885,538 | | 3,964,113 |
| **Total liabilities and shareholders' equity** | | $ | 8,409,477 | $ | 9,363,352 |

*Commitments and contingencies (Note 30)*
*The accompanying notes are an integral part of these Consolidated Financial Statements.*

These Consolidated Financial Statements were approved by the Corporation's Board of Directors on March 7, 2019.

/s/ Derek Evans

/s/ Robert B. Hodgins

Derek Evans, Director

Robert B. Hodgins, Director

**Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss)**
**(Expressed in thousands of Canadian dollars, except per share amounts)**

| Year ended December 31 | | | 2018 | | 2017 Revised (Note 3) |
|---|---|---|---|---|---|
| **Revenues** | | | | | |
| Petroleum revenue, net of royalties | 17 | $ | 2,672,845 | $ | 2,439,485 |
| Other revenue | 17 | | 59,859 | | 35,010 |
| | | | 2,732,704 | | 2,474,495 |
| **Expenses** | | | | | |
| Diluent and transportation | 18 | | 1,560,678 | | 1,158,414 |
| Operating expenses | | | 209,733 | | 222,196 |
| Purchased product | 19 | | 264,259 | | 290,656 |
| Depletion and depreciation | 7,9 | | 452,178 | | 475,644 |
| General and administrative | | | 82,686 | | 86,785 |
| Stock-based compensation | 16 | | 47,123 | | 22,528 |
| Research and development | | | 5,509 | | 5,808 |
| Net finance expense | 21 | | 285,980 | | 361,080 |
| Exploration expense | | | 978 | | — |
| Other expenses | 22 | | 27,893 | | 34,543 |
| Gain on asset dispositions | 7 | | (325,031) | | — |
| Commodity risk management loss (gain) | 27 | | (22,471) | | 49,609 |
| Foreign exchange loss (gain), net | 20 | | 311,162 | | (342,547) |
| Earnings (loss) before income taxes | | | (167,973) | | 109,779 |
| Income tax expense (recovery) | 14 | | (48,776) | | (56,197) |
| Net earnings (loss) | | | (119,197) | | 165,976 |
| Other comprehensive income (loss), net of tax | | | | | |
| Items that may be reclassified to profit or loss: | | | | | |
| Foreign currency translation adjustment | | | 16,405 | | (12,393) |
| Comprehensive income (loss) for the year | | $ | (102,792) | $ | 153,583 |
| | | | | | |
| Net earnings (loss) per common share | | | | | |
| Basic | 26 | $ | (0.40) | $ | 0.57 |
| Diluted | 26 | $ | (0.40) | $ | 0.57 |

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

**Consolidated Statement of Changes in Shareholders' Equity**
**(Expressed in thousands of Canadian dollars)**

| | Note | Share Capital | Contributed Surplus | Deficit | Accumulated Other Comprehensive Income | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| Balance as at December 31, 2017 | | **$5,403,978** | **$ 166,636** | **$ (1,629,091)** | **$ 22,590** | **$ 3,964,113** |
| IFRS 9 opening deficit adjustment | 3 | **—** | **—** | **(4,659)** | **—** | **(4,659)** |
| Stock-based compensation | 16 | **—** | **25,420** | **—** | **—** | **25,420** |
| Stock options exercised | 15 | **1,813** | **(588)** | **—** | **—** | **1,225** |
| RSUs vested and released | 15 | **21,232** | **(21,295)** | **2,294** | **—** | **2,231** |
| Comprehensive income (loss) | | **—** | **—** | **(119,197)** | **16,405** | **(102,792)** |
| **Balance as at December 31, 2018** | | **$5,427,023** | **$ 170,173** | **$ (1,750,653)** | **$ 38,995** | **$ 3,885,538** |

| | | | | | | |
|---|---|---|---|---|---|---|
| Balance as at December 31, 2016 | | $4,878,607 | $ 168,253 | $ (1,795,067) | $ 34,983 | $ 3,286,776 |
| Shares issued | 15 | 517,816 | — | — | — | 517,816 |
| Share issue costs, net of tax | 15 | (15,698) | — | — | — | (15,698) |
| Stock-based compensation | 16 | — | 21,636 | — | — | 21,636 |
| RSUs vested and released | 15 | 23,253 | (23,253) | — | — | — |
| Comprehensive income (loss) | | — | — | 165,976 | (12,393) | 153,583 |
| **Balance as at December 31, 2017** | | $5,403,978 | $ 166,636 | $ (1,629,091) | $ 22,590 | $ 3,964,113 |

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

**Consolidated Statement of Cash Flow**
**(Expressed in thousands of Canadian dollars)**

| Year ended December 31 | Note | 2018 | 2017 |
|---|---|---|---|
| **Cash provided by (used in):** | | | |
| Operating activities | | | |
| Net earnings (loss) | | $ (119,197) | $ 165,976 |
| Adjustments for: | | | |
| Depletion and depreciation | 7,9 | 452,178 | 475,644 |
| Exploration expense | | 978 | — |
| Stock-based compensation | 16 | 21,584 | 19,052 |
| Unrealized loss (gain) on foreign exchange | 20 | 340,753 | (338,144) |
| Unrealized loss (gain) on derivative financial liabilities | 21 | 3,096 | (16,179) |
| Unrealized loss (gain) on commodity risk management | 27 | (161,373) | 38,336 |
| Onerous contracts expense | 22 | 3,296 | 10,830 |
| Deferred income tax expense (recovery) | 14 | (49,679) | (56,130) |
| Amortization of debt discount and debt issue costs | 10,12 | 14,860 | 19,225 |
| Debt extinguishment expense | 12,21 | — | 30,801 |
| Gain on asset dispositions | 7 | (325,031) | — |
| Other | | 6,069 | 5,624 |
| Decommissioning expenditures | 13 | (5,225) | (2,403) |
| Payments on onerous contracts | 13 | (18,727) | (19,569) |
| Net change in other liabilities | | 5,159 | 9,389 |
| Net change in non-cash working capital items | 25 | 111,291 | (24,517) |
| **Net cash provided by (used in) operating activities** | | 280,032 | 317,935 |
| Investing activities | | | |
| Capital investments: | | | |
| Property, plant and equipment | 7 | (620,861) | (505,713) |
| Exploration and evaluation | 8 | (537) | (1,569) |
| Intangible assets | 9 | (851) | (534) |
| Net proceeds on dispositions | 7 | 1,508,729 | 5,370 |
| Other | | (9,004) | 20,983 |
| Net change in non-cash working capital items | 25 | (26,398) | 76,232 |
| **Net cash provided by (used in) investing activities** | | 851,078 | (405,231) |
| Financing activities | | | |
| Issue of shares, net of issue costs | 15 | 1,162 | 496,312 |
| Redemption of senior unsecured notes | | — | (1,008,825) |
| Issue of senior secured second lien notes | | — | 1,008,825 |
| Payments on term loan | 25 | (1,284,855) | (12,690) |
| Refinancing costs | | — | (82,377) |
| **Net cash provided by (used in) 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 and cash equivalents, beginning of year | | 463,531 | 156,230 |
| Cash and cash equivalents, end of year | | $ 317,704 | $ 463,531 |

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

## 1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange ("TSX") under the symbol "MEG". The Corporation owns a 100% interest in over 900 square miles of oil sands leases in the southern Athabasca oil sands region of northern Alberta and is primarily engaged in a steam assisted gravity drainage oil sands development at its 80 section Christina Lake Project.

In the first quarter of 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal.

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

## 2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. The consolidated financial statements have been prepared on the historical cost basis, except as detailed in the significant accounting policies disclosed in Note 3. Certain prior year amounts have been reclassified to conform to the current year presentation. These consolidated financial statements were approved by the Corporation's Board of Directors on March 7, 2019.

## 3. SIGNIFICANT ACCOUNTING POLICIES

a. Principles of consolidation

The consolidated financial statements of the Corporation comprise the Corporation and its wholly-owned subsidiary, MEG Energy (U.S.) Inc. Earnings and expenses of its subsidiary are included in the consolidated statement of earnings (loss) and comprehensive income (loss). All intercompany transactions, balances, income and expenses are eliminated on consolidation.

Prior to March 22, 2018, the Corporation owned an undivided 50% working interest in Access Pipeline and was responsible for its proportionate ownership interest of all assets and liabilities and other obligations. Since the Corporation owned an undivided interest in Access Pipeline, it held a proportionate share of the rights to the assets and obligations for the liabilities. As a result, the Corporation presented its proportionate share of the assets, liabilities, revenues and expenses of Access Pipeline on a line-by-line basis in the December 31, 2017 consolidated financial statements.

b. Foreign currency translation

i. Functional and presentation currency

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which the Corporation operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation's functional currency.

ii. Transactions and balances

Foreign currency transactions are translated into Canadian dollars at exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in a foreign currency are translated into Canadian dollars at rates of exchange in effect at the end of the period. Foreign currency differences arising on translation are recognized in earnings or loss.

For the purposes of presenting consolidated financial statements, the assets and liabilities of the foreign subsidiary are translated into Canadian dollars at rates of exchange in effect at the end of the period. Revenue and expense items are translated at the average exchange rates prevailing at the dates of the transactions. Exchange differences arising, if any, are recognized in other comprehensive income (loss).

c. Financial instruments

*Policy Applicable From January 1, 2018*

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. A financial asset or liability is measured initially at fair value plus, for an item not measured at Fair Value Through Profit or Loss, transaction costs that are directly attributable to its acquisition or issuance.

Derivative financial instruments are recognized at fair value. Transaction costs are expensed in the consolidated statement of earnings (loss) and comprehensive income (loss). Gains and losses arising from changes in fair value are recognized in net earnings (loss) in the period in which they arise.

Financial assets and liabilities at Fair Value Through Profit or Loss are classified as current except where an unconditional right to defer payment beyond 12 months exists. Derivative financial instruments are included on the balance sheet as either an asset or liability and are classified as current or non-current based on the contractual terms specific to the instrument.

Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Derivative financial instruments are included in Fair Value Through Profit or Loss unless they are designated for hedge accounting. The Corporation may periodically use derivative financial instruments to manage commodity price, foreign currency and interest rate exposures. The Corporation's commodity risk management contracts and interest rate swap contract have been classified as Fair Value Through Profit or Loss.

i. Financial assets

At initial recognition, a financial asset is classified as measured at: amortized cost, Fair Value Through Profit or Loss or Fair Value Through Other Comprehensive Income depending on the business model and contractual cash flows of the instrument.

Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Corporation has transferred substantially all risks and rewards of ownership. A substantial modification to the terms of an existing financial asset results in the derecognition of the financial asset and the recognition of a new financial asset at fair value. In the event that the modification to the terms of an existing financial asset do not result in a substantial difference in the contractual cash flows the gross carrying amount of the financial asset is recalculated and the difference resulting from the adjustment in the gross carrying amount is recognized in earnings or loss.

ii. Financial liabilities

Financial liabilities are measured at amortized cost or Fair Value Through Profit or Loss. Financial liabilities at amortized cost include accounts payable and accrued liabilities and long-term debt. Accounts payable and accrued liabilities are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Long-term debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

Financial liabilities are derecognized when the liability is extinguished. A substantial modification of the terms of an existing financial liability is recorded as an extinguishment of the original financial liability and the recognition of a new financial liability. The difference between the carrying amount of a financial liability extinguished and the consideration paid is recognized in earnings or loss. Where a financial liability is modified in a way that does not constitute an extinguishment (generally when there is a change of less than 10% in the present value of cash flows discounted at the original effective interest rate), the modified cash flows are discounted at the liability's original effective interest rate. Transaction costs paid to third parties in a modification are amortized over the remaining term of the modified debt.

*Policy Applicable Before January 1, 2018*

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Corporation has transferred substantially all risks and rewards of ownership. Financial liabilities are derecognized when the liability is extinguished. A substantial modification of the terms of an existing financial liability is recorded as an extinguishment of the original financial liability and the recognition of a new financial liability. The difference between the carrying amount of a financial liability extinguished and the consideration paid is recognized in earnings or loss. If the modification is not treated as an extinguishment, any costs or fees incurred adjust the carrying amount of the liability and are amortized over the remaining term of the modified liability.

Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

At initial recognition, the Corporation classifies its financial instruments in the following categories depending on the purpose for which the instruments were acquired:

i. Financial assets and liabilities at fair value through earnings or loss

A financial asset or liability is classified in this category if acquired principally for the purpose of selling or repurchasing in the short term.

Derivative financial instruments are also included in this category unless they are designated for hedge accounting. The Corporation may periodically use derivative financial instruments to manage commodity price, foreign currency and interest rate exposures. The Corporation’s derivative financial liabilities and commodity risk management contracts have been classified as fair value through earnings or loss.

Financial instruments are recognized initially and subsequently at fair value. Transaction costs are expensed in the consolidated statement of earnings (loss) and comprehensive income (loss). Gains and losses arising from changes in fair value are recognized in net earnings (loss) in the period in which they arise. Financial assets and liabilities at fair value through earnings or loss are classified as current except for any portion expected to be realized or paid beyond twelve months from the balance sheet date. Derivative financial instruments are included on the balance sheet as either an asset or liability and are classified as current or non-current based on the contractual terms specific to the instrument. The derivative financial instruments include the Corporation’s commodity risk management contracts, the interest rate swap included in other assets and the derivative financial liability included in provisions and other liabilities.

ii. Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. The Corporation's loans and receivables are comprised of cash and cash equivalents and trade receivables and other, and are included in current assets due to their short-term nature.

Loans and receivables are initially recognized at the amount expected to be received less any required discount to reduce the loans and receivables to fair value. Subsequently, loans and receivables are measured at amortized cost using the effective interest method less any provision for impairment.

iii. Financial liabilities at amortized cost

Financial liabilities at amortized cost include accounts payable and accrued liabilities and long-term debt. Accounts payable and accrued liabilities are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Long-term debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

Financial liabilities are classified as current liabilities if payment is mandatory within twelve months from the balance sheet date. Otherwise, they are presented as non-current liabilities.

d. Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held with banks, and other short-term highly liquid investments such as bankers' acceptances, commercial paper, money market deposits or similar instruments, with a maturity of 90 days or less.

e. Trade receivables and other

Trade receivables are recorded based on the Corporation's revenue recognition policy as described in Note 3(r). Other amounts include deposits and advances which include funds placed in escrow in accordance with the terms of certain agreements, funds held in trust in accordance with governmental regulatory requirements and funds advanced to joint operation partners. Any impairments are determined based on the Corporation's impairment policy as described in Note 3(m)(i).

f. Inventories

Inventories consist of crude oil products and materials and supplies. Inventory is valued at the lower of cost and net realizable value. The cost of bitumen blend inventory is determined on a weighted average cost basis and the cost of diluent inventory is based on purchase price. Costs include direct and indirect expenditures incurred in the normal course of business in bringing an item or product to its existing condition and location. Net realizable value is the estimated selling price less applicable selling expenses. If the carrying value exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if the inventory is still on hand but the circumstances which caused the write-down no longer exist.

g. Exploration and evaluation assets

Exploration and evaluation ("E&E") expenditures, including the costs of acquiring licenses, technical studies, exploration drilling and evaluation and directly attributable general and administrative costs, including related borrowing costs, are initially capitalized as exploration and evaluation assets. Costs incurred prior to obtaining a legal right or license to explore are expensed in the period in which they are incurred.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. Upon determination of proved or probable reserves, E&E assets attributable to those reserves are tested for impairment upon reclassification to property, plant and equipment. If it is determined that an E&E asset is not technically feasible or commercially viable or facts and circumstances suggest that the carrying amount exceeds the recoverable amount, and the Corporation decides to discontinue the exploration and evaluation activity, the unrecoverable costs are charged to expense.

An E&E asset is derecognized upon disposal and any gains or losses from disposition are recognized in net earnings or loss.

h. Property, plant and equipment

Property, plant and equipment (“PP&E”) is measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Assets under construction are not subject to depletion and depreciation. When significant parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components).

i. Crude oil

Crude oil assets consist of field production assets, major facilities and equipment, and planned major inspections, overhaul and turnaround activities. Included in the costs of these assets are the acquisition, construction, development and production of crude oil sands properties and reserves, including directly attributable overhead and administrative costs, related borrowing costs and estimates of decommissioning liability costs.

Field production assets are depleted using the unit-of-production method based on estimated proved reserves. Costs subject to depletion include estimated future development costs required to develop and produce the proved reserves. These estimates are reviewed by independent reserve engineers at least annually.

Major facilities and equipment are depreciated on a unit-of-production basis over the estimated total productive capacity of the facilities.

Costs of planned major inspections, overhaul and turnaround activities that maintain PP&E and benefit future years of operations are capitalized and depreciated on a straight-line basis over the period to the next turnaround. Recurring planned maintenance activities performed on shorter intervals are expensed. Replacements of equipment are capitalized when it is probable that future economic benefits will flow to the Corporation.

ii. Transportation and storage

Transportation and storage assets consist primarily of the Corporation’s undivided 50% joint operations interest in the Access Pipeline, the Corporation's wholly-owned Stonefell Terminal and other transportation and storage assets. The net carrying values of transportation and storage assets are depreciated on a straight-line basis over their estimated 50 year useful lives. On March 22, 2018, the Corporation completed the sale of its wholly-owned Stonefell Terminal and its 50% interest in the Access Pipeline.

iii. Corporate assets

Corporate assets consist primarily of office equipment, computer hardware and leasehold improvements. Depreciation of office equipment is provided over the useful life of the assets on the declining balance basis at 25% per year. Leasehold improvements are depreciated on a straight-line basis over the term of the lease.

i. Borrowing costs

Borrowing costs incurred for the construction of a qualifying asset are capitalized when a substantial period of time is required to complete and prepare the asset for its intended use. The capitalization of borrowing costs is suspended during extended periods in which the Corporation suspends active development of the asset and ceases when the asset is in the location and condition necessary for its intended use. All other borrowing costs are recognized in net finance expense using the effective interest method.

j. Intangible assets

Intangible assets acquired by the Corporation which have a finite useful life are carried at cost less accumulated depreciation. Subsequent expenditures are capitalized only to the extent that they increase the future economic benefits embodied in the asset to which they relate. The Corporation incurs costs associated with research and development. Expenditures during the research phase are expensed. Expenditures during the development phase are capitalized only if certain criteria, including technical feasibility and the intent to develop and use the technology, are met. If these criteria are not met, the costs are expensed as incurred. The cost associated with purchasing or creating software which is not an integral component of the related computer hardware is included within intangible assets. The net carrying value of software is amortized over the useful life of the asset on the declining balance basis at 25% per year.

k. Other assets - non-current pipeline linefill

The Corporation transports bitumen blend and diluent on third-party pipelines for which it is required to supply linefill. As these pipelines are owned by third parties, the linefill is not considered to be a component of the Corporation's PP&E. The linefill is classified as either a current or non-current asset based on the term of the related transportation contract. The linefill is carried at the lower of cost or net realizable value. If the carrying value exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if the circumstances which caused the write-down no longer exist.

l. Leases

Leases where the Corporation assumes substantially all the risks and rewards of ownership are classified as finance leases within PP&E. At the commencement of the lease term, the Corporation recognizes the finance lease as an asset and a corresponding liability on the consolidated balance sheet at an amount equal to the lower of its fair value and the present value of the minimum lease payments. The Corporation's estimated incremental borrowing rate is used to calculate the present value of the minimum lease payments.

Minimum lease payments are apportioned between the finance charge and the reduction of the finance lease liability. Finance charges are charged directly against income through Net Finance Expense. The finance lease liability is accreted over the life of the lease and reduced by actual lease payments.

All other leases are operating leases, which are recognized as an expense as incurred over the lease term. When lease inducements are received to enter into operating leases, such inducements are recognized as a deferred liability. The aggregate benefit of inducements is recognized as a reduction of the related lease expense on a straight-line basis, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed.

A sale and leaseback transaction involves the sale of an asset and the leasing back of the same asset. If a sale and leaseback transaction results in a finance lease, any excess of sales proceeds over the carrying amount is not immediately recognized as income by the Corporation as a seller-lessee. Instead, the excess is deferred and amortized over the lease term. If a sale and leaseback results in an operating lease, and it is clear that the transaction is established at fair value, any profit or loss is recognized immediately.

m. Impairments

i. Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired.

Loss allowances are measured at an amount equal to the lifetime expected credit losses on the asset. Expected credit losses are a probability-weighted estimate of credit losses and are measured as the present value of all cash shortfalls for financial assets that are not credit-impaired at the reporting date and as the difference between the gross carrying amount and the present value of estimated future cash flows for financial assets that are credit-impaired at the reporting date. Loss allowances for expected credit losses for financial assets measured at amortized cost are presented in the statement of financial position as a deduction from the gross carrying amount of the asset.

ii. Non-financial assets

PP&E and E&E assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated. Intangible assets that are not yet available for use are tested for impairment annually. E&E assets are assessed for impairment immediately prior to being reclassified to PP&E.

For the purpose of impairment testing, PP&E assets are grouped into cash-generating units (“CGU”). A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. E&E assets are allocated to related CGU’s for impairment testing.

The recoverable amount of a CGU is the greater of its value in use and its fair value less costs of disposal. Value in use is estimated as the discounted present value of the expected future cash flows to be derived from the continuing use of the asset or CGU. In determining fair value less costs of disposal, recent market transactions are taken into account if available. In the absence of such transaction, an appropriate valuation model is used. An impairment loss is recognized in earnings or loss if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimate used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

n. Provisions

i. General

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are measured at the present value of the estimated future cash flows. Subsequent to the initial measurement, provisions are adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation as well as any changes in the discount rate.

ii. Decommissioning provision

The Corporation's activities give rise to dismantling, decommissioning and restoration activities. A provision is made for the estimated cost of decommissioning and restoration activities and capitalized in the relevant asset category.

Increases in the decommissioning provision due to the passage of time are recognized in net finance expense whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the obligations are charged against the decommissioning provision.

iii. Onerous contracts

A provision for an onerous contract is recognized when the unavoidable cost of meeting the obligations under the contract exceed the economic benefits expected to be derived from the contract. The net amount of actual costs incurred and sublease recoveries earned are charged against the onerous contract provision.

iv. Emissions obligations

When required, emission liabilities are recorded at the estimated cost required to settle the obligation. Emission compliance costs are expensed when incurred. Emission allowances granted to or internally generated by the Corporation are recognized as intangible assets at a nominal amount.

o. Deferred income taxes

The Corporation follows the liability method of accounting for income taxes. Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred taxes are not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. Deferred 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 as at the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority.

A deferred tax asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Income taxes are recognized in net earnings except to the extent that they relate to items recognized directly in shareholders' equity, in which case the income taxes are recognized in shareholders' equity.

p. Share capital

Common shares are classified as equity. Transaction costs directly attributable to the issuance of shares are recognized as a reduction of shareholders' equity, net of any related income tax.

q. Share based payments

The Corporation's share-based compensation plans include equity-settled awards and cash-settled awards. Compensation expense is recorded as stock based compensation expense or capitalized when the cost directly relates to exploration or development activities.

i. Equity-settled

The Corporation grants equity-settled stock options, restricted share units ("RSUs") and performance share units ("PSUs") to directors, officers, employees and consultants. The grant date fair value of stock options, RSUs and PSUs is recognized as stock-based compensation expense, with a corresponding increase in contributed surplus, over the vesting period of the options, RSUs and PSUs. Each tranche in an award is considered a separate grant with its own vesting period and grant date fair value. Fair value is determined using the Black-Scholes option pricing model. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options, RSUs and PSUs that vest.

The Corporation's equity-settled RSU Plan allows the holder of an RSU or PSU to receive a cash payment or its equivalent in fully-paid common shares, at the Corporation's discretion, equal to the fair market value of the Corporation's common shares calculated at the date of such payment. The Corporation does not intend to make cash payments under the equity-settled RSU Plan and, as such, the RSUs and PSUs are accounted for within shareholders' equity. On exercise of stock options, the cash consideration received by the Corporation is credited to share capital and the associated amount in contributed surplus is reclassified to share capital.

ii. Cash-settled

The Corporation grants cash-settled RSUs and PSUs to directors, officers, employees and consultants. Cash-settled RSUs and PSUs are accounted for as liability instruments and are measured at fair value based on the market value of the Corporation's common shares at each period end. The fair value is recognized as stock-based compensation over the vesting period. Fluctuations in the fair value are recognized within stock-based compensation in the period in which they occur.

The Corporation's cash-settled RSU Plan allows the holder of an RSU or PSU to receive a cash payment, at the Corporation's discretion, equal to the fair market value of the Corporation's common shares calculated at the date of such payment.

The Corporation grants cash-settled deferred share units ("DSUs") to directors of the Corporation. DSUs are accounted for as liability instruments and are measured at fair value based on the market price of the Corporation's common shares. The fair value of a DSU is recognized as stock-based compensation expense on the grant date and future fluctuations in the fair value are recognized as stock-based compensation expense in the period in which they occur.

r. Revenue recognition

The Corporation earns revenue primarily from the sale of crude oil, with other revenue earned from excess power generation, and from transportation fees charged to third parties.

i. Petroleum revenue and royalties

The Corporation sells proprietary and purchased crude oil under contracts of varying terms of up to one year to customers at prevailing market prices, whereby delivery takes place throughout the contract period. In most cases, consideration is due when title has transferred and is generally collected in the month following the month of delivery.

The Corporation evaluates its arrangements with third parties to determine if the Corporation acts as the principal or as an agent. In making this evaluation, management considers if the Corporation obtains control of the product delivered. If the Corporation acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the Corporation from the transaction.

Revenues associated with the sales of proprietary and purchased crude oil owned by the Corporation are recognized at a point in time when control of goods have transferred, which is generally when title passes from the Corporation to the customer. Revenues are recorded net of crown royalties. Crown royalties are recognized at the time of production.

Revenue is allocated to each performance obligation on the basis of its standalone selling price and measured at the transaction price, which is the fair value of the consideration and represents amounts receivable for goods or services provided in the normal course of business. The price is allocated to each unit in the series as each unit is substantially the same and depicts the same pattern of transfer to the customer.

ii. Other revenue

Revenue from power generated in excess of the Corporation's internal requirements is recognized upon delivery from the plant gate, at which point, control is transferred to the customer on the power grid. Revenues are earned at prevailing market prices for each megawatt hour produced. Fees charged to customers for the use of pipelines and facilities are recognized in the period when the products are delivered and the services are provided.

iii. Asset dispositions

Property, plant and equipment assets are derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising from derecognition of the asset is determined as the difference between the net disposal proceeds, if any, and the carrying amount of the asset, and is recognized in net earnings or loss, unless the disposition is part of a sale and leaseback. The amount of consideration to be included in the gain or loss arising from derecognition is determined by the transaction contract.

Dispositions of property, plant and equipment occur on the date the acquiror obtains control of the asset.

s. Net earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing the net earnings (loss) for the period attributable to common shareholders of the Corporation by the weighted average number of common shares outstanding during the period.

Diluted earnings (loss) per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to stock options, RSUs and PSUs is computed using the treasury stock method. The Corporation's potentially dilutive instruments comprise stock options, and equity-settled RSUs and PSUs granted to directors, officers, employees and consultants.

t. New accounting standards

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

i. 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.

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.

ii. 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.

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[(a)] | $ | 6,381 |
| Tax effect | | (1,722) |
| **Increase to opening deficit** | **$** | **4,659** |

(a) *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.*

iii. 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.

u. Accounting standards issued but not yet applied

i. 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.

## 4. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGMENTS

The timely preparation of the consolidated financial statements requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ materially from estimated amounts as future confirming events occur. Significant judgments, estimates and assumptions made by management in the preparation of these consolidated financial statements are outlined below.

a. 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.

b. 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.

c. 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.

d. Provisions

i. 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.

ii. 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.

e. 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.

f. 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.

g. 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.

h. 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.

i. 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.

## 5. TRADE RECEIVABLES AND OTHER

| **As at December 31** | | **2018** | | **2017** |
|---|---|---|---|---|
| Trade receivables | **$** | **200,606** | $ | 266,789 |
| Deposits and advances | | **10,035** | | 13,189 |
| Current portion of deferred financing costs | | **7,562** | | 8,653 |
| Current portion of interest rate swaps | | **—** | | 473 |
| | **$** | **218,203** | $ | 289,104 |

## 6. INVENTORIES

| **As at December 31** | | **2018** | | **2017** |
|---|---|---|---|---|
| Bitumen blend | **$** | **74,292** | **$** | **64,077** |
| Diluent | | **17,333** | | **19,576** |
| Material and supplies | | **5,889** | | **2,197** |
| | **$** | **97,514** | **$** | **85,850** |

During the year ended December 31, 2018, a total of $1.3 billion (2017 - $0.9 billion) in inventory product costs were charged to earnings through diluent and transportation expense.

## 7. PROPERTY, PLANT AND EQUIPMENT

| | Crude oil | Transportation and storage | Corporate assets | Total |
|---|---|---|---|---|
| **Cost** | | | | |
| Balance as at December 31, 2016 | $ 7,878,009 | $ 1,610,118 | $ 55,983 | $ 9,544,110 |
| Additions | 478,782 | 8,645 | 20,465 | 507,892 |
| Dispositions | (24,102) | — | — | (24,102) |
| Change in decommissioning liabilities | (34,599) | (922) | — | (35,521) |
| Balance as at December 31, 2017 | $ 8,298,090 | $ 1,617,841 | $ 76,448 | $ 9,992,379 |
| Additions | 618,725 | 201,583 | 773 | 821,081 |
| Transfers to other assets (Note 10) | — | (67,318) | — | (67,318) |
| Dispositions | — | (1,397,099) | — | (1,397,099) |
| Change in decommissioning liabilities | (37,087) | (329) | — | (37,416) |
| **Balance as at December 31, 2018** | **$ 8,879,728** | **$ 354,678** | **$ 77,221** | **$ 9,311,627** |
| **Accumulated depletion and depreciation** | | | | |
| Balance as at December 31, 2016 | $ 1,766,709 | $ 110,833 | $ 27,134 | $ 1,904,676 |
| Depletion and depreciation | 436,271 | 29,801 | 5,964 | 472,036 |
| Dispositions | (18,732) | — | — | (18,732) |
| Balance as at December 31, 2017 | $ 2,184,248 | $ 140,634 | $ 33,098 | $ 2,357,980 |
| Depletion and depreciation | 425,505 | 22,306 | 6,364 | 454,175 |
| Dispositions | — | (145,752) | — | (145,752) |
| **Balance as at December 31, 2018** | **$ 2,609,753** | **$ 17,188** | **$ 39,462** | **$ 2,666,403** |
| **Carrying amounts** | | | | |
| Balance as at December 31, 2017 | $ 6,113,842 | $ 1,477,207 | $ 43,350 | $ 7,634,399 |
| **Balance as at December 31, 2018** | **$ 6,269,975** | **$ 337,490** | **$ 37,759** | **$ 6,645,224** |

During the first quarter of 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for proceeds of $1.52 billion (net of transaction costs of $18.5 million). As a result of the transaction, the Corporation recognized a gain of $318.4 million on the sale of its 50% interest in the Access Pipeline. The sale of its 100% interest in the Stonefell Terminal has been accounted for as a sale and leaseback transaction that results in a finance lease (Note 13(a)). The $190.8 million net book value of the leased asset is included in transportation and storage assets within property, plant and equipment. The Stonefell Lease Agreement is a 30-year arrangement that secures the Corporation's operational control and exclusive use of 100% of Stonefell Terminal's 900,000 barrel blend and condensate facility.

As at December 31, 2018, property, plant and equipment was assessed for impairment and no impairment was recognized. Included in the cost of property, plant and equipment is $291.0 million of assets under construction (December 31, 2017 – $459.7 million).

## 8. EXPLORATION AND EVALUATION ASSETS

| **Cost** | | |
|---|---|---|
| Balance as at December 31, 2016 | $ | 547,752 |
| Additions | | 1,569 |
| Change in decommissioning liabilities | | (493) |
| Balance as at December 31, 2017 | $ | 548,828 |
| Additions | | 2,906 |
| Exploration expense and dispositions | | (978) |
| Change in decommissioning liabilities | | (736) |
| **Balance as at December 31, 2018** | **$** | **550,020** |

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. These assets are not subject to depletion, as they are in the exploration and evaluation stage, but are reviewed on a quarterly basis for any indication of impairment. If it is determined that the project is not technically feasible and commercially viable or if the Corporation decides not to continue the exploration and evaluation activity, the unrecoverable accumulated costs are expensed as exploration expense. As at December 31, 2018, these assets were assessed for impairment and no impairment has been recognized on exploration and evaluation assets.

## 9. INTANGIBLE ASSETS

| **Cost** | | |
|---|---|---|
| Balance as at December 31, 2016 | $ | 112,921 |
| Additions | | 534 |
| Balance as at December 31, 2017 | $ | 113,455 |
| Additions | | 851 |
| **Balance as at December 31, 2018** | **$** | **114,306** |

| **Accumulated depreciation** | | |
|---|---|---|
| Balance as at December 31, 2016 | $ | 96,810 |
| Depreciation | | 3,608 |
| Balance as at December 31, 2017 | $ | 100,418 |
| Depreciation | | 2,940 |
| **Balance as at December 31, 2018** | **$** | **103,358** |

| **Carrying amounts** | | |
|---|---|---|
| Balance as at December 31, 2017 | $ | 13,037 |
| **Balance as at December 31, 2018** | **$** | **10,948** |

As at December 31, 2018, intangible assets consist of $10.9 million invested in software that is not an integral component of the related computer hardware (December 31, 2017 – $13.0 million). As at December 31, 2018, no impairment has been recognized on these assets.

## 10. OTHER ASSETS

| As at December 31 | | 2018 | | 2017 |
|---|---|---|---|---|
| Non-current pipeline linefill[(a)] | **$** | **194,066** | $ | 122,657 |
| Deferred financing costs | | **15,481** | | 24,134 |
| Prepaid transportation costs[(b)] | | **8,643** | | — |
| Interest rate swap[(c)] | | **—** | | 8,067 |
| | | **218,190** | | 154,858 |
| Less current portion | | **(7,562)** | | (9,126) |
| | **$** | **210,628** | $ | 145,732 |

a. Non-current pipeline linefill on third party owned pipelines is classified as a non-current asset as these transportation contracts expire between the years 2025 and 2048. As a result of the sale of the Corporation's 50% interest in Access Pipeline and its 100% interest in the Stonefell Terminal in the first quarter of 2018, $67.3 million of the associated pipeline linefill was transferred from property, plant and equipment to other assets. As at December 31, 2018, no impairment has been recognized on these assets.

b. During the year ended December 31, 2018, the Corporation invested $8.6 million to upgrade third-party transportation infrastructure under the terms of a non-current transportation services agreement. The prepaid expenditures have been capitalized and will be amortized to transportation expense over the 30-year term of the agreement, once the transportation infrastructure is available for use.

c. In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of its US$1.2 billion senior secured term loan at approximately 5.3%. In conjunction with the March 2018 partial repayment of the senior secured term loan, the interest rate swap was terminated and a realized gain of $17.3 million was recognized (Note 21).

## 11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

| As at December 31 | | 2018 | | 2017 |
|---|---|---|---|---|
| Accrued and other liabilities | **$** | **336,986** | $ | 333,988 |
| Interest payable | | **84,095** | | 77,625 |
| Trade payables | | **5,272** | | 2,292 |
| | **$** | **426,353** | $ | 413,905 |

## 12. LONG-TERM DEBT

| As at December 31 | 2018 | 2017 |
|---|---|---|
| Senior secured term loan (December 31, 2018 – US$225.4 million; due 2023; December 31, 2017 – US$1.226 billion)[(a)] | $ 307,552 | $ 1,534,378 |
| 6.375% senior unsecured notes (US$800.0 million; due 2023) [(b)] | 1,091,640 | 1,001,440 |
| 7.0% senior unsecured notes (US$1.0 billion; due 2024)[(c)] | 1,364,550 | 1,251,800 |
| 6.5% senior secured second lien notes (US$750.0 million; due 2025)[(d)] | 1,023,413 | 938,850 |
| | 3,787,155 | 4,726,468 |
| Less unamortized financial derivative liability discount | (1,267) | (4,242) |
| Less unamortized deferred debt discount and debt issue costs[(a)(b)] | (28,886) | (38,499) |
| | 3,757,002 | 4,683,727 |
| Less current portion of senior secured term loan | (16,852) | (15,460) |
| | $ 3,740,150 | $ 4,668,267 |

| | 2019 | 2020 | 2021 | 2022 | 2023 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Required debt principal repayments | $ 16,852 | $ 16,852 | $ 16,852 | $ 16,852 | $ 1,331,784 | $ 2,387,963 | $ 3,787,155 |

The U.S. dollar denominated debt was translated into Canadian dollars at the year end exchange rate of US$1 = C $1.3646 (December 31, 2017 – US$1 = C$1.2518).

All of the Corporation's long-term debt is "covenant-lite" in structure, meaning it is free of any financial maintenance covenants and is not dependent on, nor calculated from, the Corporation's crude oil reserves.

a. Effective January 27, 2017, the Corporation refinanced and extended the maturity date of its US$1.2 billion term loan from March 2020 to December 2023. The term loan bears interest at an annual rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 2.5% or 3.5%, respectively. The term loan also has a U.S. Prime Rate floor of 2.0% and a LIBOR floor of 1.0%. The term loan is repaid in quarterly installment payments of US$3.1 million, with the balance due on December 31, 2023. The term loan was issued at a price equal to 99.75% of its face value. The Corporation has deferred the debt discount and the associated debt issue costs of $22.0 million and is amortizing these costs over the life of the loan utilizing the effective interest method.

   Effective January 27, 2017, the Corporation extended the maturity date on substantially all of its commitments under the Corporation's covenant-lite revolving credit facility from November 2019 to November 2021. The commitment amount of the five-year facility has been reduced from US$2.5 billion to US$1.4 billion. As at December 31, 2018, no amount has been drawn under the revolving credit facility.

   On February 15, 2017, the Corporation extended the maturity date on the Corporation's five-year letter of credit facility, guaranteed by Export Development Canada, from November 2019 to November 2021. The guaranteed letter of credit facility has been reduced from US$500 million to 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 amendments to the term loan, revolving credit facility and guaranteed letter of credit facility were not considered to be new financial liabilities, as no substantial modifications arose between the existing and amended agreements. As a result, no profit or loss was recognized when the terms of the financial liabilities were amended.

   On March 27, 2018, subsequent to the sale of the Corporation's 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 $1.2 billion of the senior secured term loan (Note 7). The repayment of debt 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 at 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.

As at December 31, 2018, the senior secured credit facilities are comprised of a US$225.4 million term loan and a US$1.4 billion revolving credit facility. The senior secured term loan, credit facilities and second lien notes are secured by substantially all the assets of the Corporation.

b. Effective July 19, 2012, the Corporation issued US$800.0 million in aggregate principal amount of 6.375% senior unsecured notes, with a maturity date of January 30, 2023. Interest is paid semi-annually on January 30 and July 30. No principal payments are required until January 30, 2023.

c. Effective October 1, 2013, the Corporation issued US$800.0 million in aggregate principal amount of 7.0% senior unsecured notes, with a maturity date of March 31, 2024. On November 6, 2013 an additional US$200 million of 7.0% senior unsecured notes were issued under the same indenture. Interest is paid semi-annually on March 31 and September 30. No principal payments are required until March 31, 2024.

d. Effective January 27, 2017, the Corporation issued US$750 million in aggregate principal amount of 6.5% senior secured second lien notes, with a maturity date of January 15, 2025. Interest is paid semi-annually in January and July. No principal payments are required until 2025. The Corporation has deferred the associated debt issue costs of $18.1 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

## 13. PROVISIONS AND OTHER LIABILITIES

| As at December 31 | | 2018 | | 2017 |
|---|---|---|---|---|
| Finance leases[(a)] | $ | 131,063 | $ | — |
| Onerous contracts provision[(b)] | | 77,625 | | 92,157 |
| Decommissioning provision[(c)] | | 64,965 | | 102,530 |
| Deferred lease inducements[(d)] | | 20,932 | | 22,854 |
| Other liabilities | | 16,290 | | 15,417 |
| Provisions and other liabilities | | 310,875 | | 232,958 |
| Less current portion | | (17,058) | | (27,446) |
| Non-current portion | $ | 293,817 | $ | 205,512 |

a. Finance leases:

| As at December 31 | | 2018 | | 2017 |
|---|---|---|---|---|
| Balance, beginning of year | $ | — | $ | — |
| Liabilities incurred | | 130,446 | | — |
| Liabilities settled | | (12,166) | | — |
| Interest expense | | 12,783 | | — |
| Balance, end of year | $ | 131,063 | $ | — |

On March 22, 2018, the Corporation successfully completed the sale of its 100% interest in the Stonefell Terminal. Concurrently, the Corporation entered into a Stonefell Lease Agreement, which is a 30-year arrangement that secures the Corporation's operational control and use of 100% of the Stonefell Terminal. The sale of the Stonefell Terminal and the Stonefell Lease Agreement were accounted for as a sale and leaseback transaction that resulted in a finance lease. The lease payments are escalated at 1% per year and the Corporation is entitled to unlimited renewal terms. The total undiscounted amount of the estimated future cash flows to settle the lease obligations over the remaining lease term is $534.2 million. At the time the Corporation entered into the lease agreement, the Corporation estimated the net present value of the lease obligations using an estimated incremental borrowing rate of 13.5%.

The Corporation's minimum lease payments are as follows:

| **As at December 31** | | **2018** |
|---|---|---|
| Within one year | **$** | **15,768** |
| Later than one year but not later than five years | | **64,800** |
| Later than five years | | **453,681** |
| Minimum lease payments | | **534,249** |
| Amounts representing finance charges | | **(403,186)** |
| Present value of net minimum lease payments | **$** | **131,063** |

b. Onerous contracts provision:

| **As at December 31** | | **2018** | | **2017** |
|---|---|---|---|---|
| Balance, beginning of year | **$** | **92,157** | $ | 100,159 |
| Changes in estimated future cash flows | | **2,688** | | 13,337 |
| Changes in discount rates | | **608** | | (2,507) |
| Liabilities settled | | **(18,727)** | | (19,569) |
| Accretion | | **899** | | 737 |
| Balance, end of year | | **77,625** | | 92,157 |
| Less current portion | | **(12,572)** | | (19,047) |
| Non-current portion | **$** | **65,053** | $ | 73,110 |

As at December 31, 2018, the Corporation has recognized a provision of $77.6 million related to onerous office building lease contracts (December 31, 2017 – $92.2 million). The provision represents the present value of the difference between the minimum future payments that the Corporation is obligated to make under the non-cancellable onerous lease contracts and estimated recoveries. The total undiscounted amount of the estimated future cash flows to settle the onerous contracts obligations is $86.5 million (December 31, 2017 – $102.1 million). These cash flows have been discounted using a risk-free discount rate of 1.9% (December 31, 2017 – 1.8%). This estimate may vary as a result of changes in estimated recoveries. The onerous contracts obligation is estimated to be settled in periods up to the year 2031 (December 31, 2017 - periods up to the year 2031).

c. Decommissioning provision:

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

| As at December 31 | 2018 | 2017 |
|---|---|---|
| Balance, beginning of year | $ 102,530 | $ 133,924 |
| Changes in estimated future cash flows and settlement dates | (4,983) | (36,314) |
| Changes in discount rates | (39,132) | (19,602) |
| Liabilities incurred | 6,013 | 19,902 |
| Liabilities disposed | (976) | — |
| Liabilities settled | (5,225) | (2,403) |
| Accretion | 6,738 | 7,023 |
| Balance, end of year | 64,965 | 102,530 |
| Less current portion | (2,557) | (6,386) |
| Non-current portion | $ 62,408 | $ 96,144 |

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The total undiscounted amount of the estimated future cash flows to settle the decommissioning obligations is $719.4 million (December 31, 2017 – $859.1 million). The Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 14.1% (December 31, 2017 – 9.5%) and an inflation rate of 2.1% (December 31, 2017 - 2.1%). The decommissioning provision is estimated to be settled in periods up to the year 2067 (December 31, 2017 - periods up to the year 2067).

d. Deferred office building lease inducements:

Deferred lease inducements of $20.9 million are being amortized over the respective terms of the Corporation's office building leases.

## 14. INCOME TAXES

| Year ended December 31 | | 2018 | | 2017 |
|---|---|---|---|---|
| Expected income tax expense (recovery) | $ | **(45,353)** | $ | 29,640 |
| Add (deduct) the tax effect of: | | | | |
| Stock-based compensation | | **5,828** | | 5,144 |
| Non-taxable loss (gain) on foreign exchange | | **46,649** | | (46,390) |
| Taxable capital loss (gain) not recognized | | **46,649** | | (46,390) |
| Non-taxable loss (gain) on sale of assets | | **(49,358)** | | — |
| Taxable loss (gain) shelter by losses | | **(49,358)** | | — |
| Tax benefit of vested RSUs | | **(3,703)** | | (1,166) |
| Other | | **(130)** | | 2,965 |
| Income tax expense (recovery) | $ | **(48,776)** | $ | (56,197) |
| | | | | |
| Current income tax expense (recovery) | $ | **903** | $ | (67) |
| Deferred income tax expense (recovery) | | **(49,679)** | | (56,130) |
| Income tax expense (recovery) | $ | **(48,776)** | $ | (56,197) |

During the year ended December 31, 2018, the Corporation recognized a current income tax expense of $0.9 million (year ended December 31, 2017 - $0.1 million income tax recovery). The expense is comprised of $0.9 million relating to United States income tax associated with operations in the United States. The 2017 recovery was primarily related to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures, partially offset by United States income tax associated with operations in the United States.

As at December 31, 2018, the Corporation has recognized a deferred tax asset of $236.6 million (December 31, 2017 - $182.9 million). Future taxable income is expected to be sufficient to realize the deferred tax asset. The deferred tax asset is reviewed at each balance sheet date to assess whether it is probable that the related tax benefit will be realized.

The deferred tax assets (liabilities) consist of the following:

| As at December 31 | | 2018 | | 2017 |
|---|---|---|---|---|
| Deferred tax assets: | | | | |
| Deferred tax assets to be recovered after more than 12 months | $ | **1,419,790** | $ | 1,381,512 |
| Deferred tax assets to be recovered within 12 months | | **12,469** | | 29,856 |
| | $ | **1,432,259** | $ | 1,411,368 |
| Deferred tax liabilities: | | | | |
| Deferred tax liabilities to be recovered after more than 12 months | $ | **(1,168,663)** | $ | (1,228,497) |
| Deferred tax liabilities to be recovered within 12 months | | **(27,018)** | | — |
| | $ | **(1,195,681)** | $ | (1,228,497) |
| Deferred tax assets (liabilities), net | $ | **236,578** | $ | 182,871 |

The net movement within the deferred tax assets (liabilities) is as follows:

| | 2018 | 2017 |
|---|---|---|
| Balance as at January 1 | $ 182,871 | $ 120,944 |
| Credited (charged) to earnings | 49,679 | 56,130 |
| Credited (charged) to other comprehensive income | 13 | (9) |
| Credited (charged) to equity | 4,015 | 5,806 |
| Balance as at December 31 | $ 236,578 | $ 182,871 |

The movements in deferred income tax assets and liabilities during the years are as follows:

| Deferred tax assets | Tax losses | Commodity Risk Management | Provisions | Other | Total |
|---|---|---|---|---|---|
| Balance as at December 31, 2016 | $ 1,208,055 | $ 9,187 | $ 3,787 | $ 52,125 | $ 1,273,154 |
| Credited (charged) to earnings | 123,110 | 8,798 | 1,247 | 5,068 | 138,223 |
| Credited (charged) to other comprehensive income | — | — | — | (9) | (9) |
| Balance as at December 31, 2017 | $ 1,331,165 | $ 17,985 | $ 5,034 | $ 57,184 | $ 1,411,368 |
| Credited (charged) to earnings | 37,822 | (17,985) | 158 | (3,132) | 16,863 |
| Credited (charged) to equity | 2,292 | — | — | 1,723 | 4,015 |
| Credited (charged) to other comprehensive income | — | — | — | 13 | 13 |
| **Balance as at December 31, 2018** | **$ 1,371,279** | **$ —** | **$ 5,192** | **$ 55,788** | **$ 1,432,259** |

| Deferred tax liabilities | Property, plant and equipment | Commodity Risk Management | Leases | Other | Total |
|---|---|---|---|---|---|
| Balance as at December 31, 2016 | $ (1,142,424) | $ — | $ — | $ (9,786) | $ (1,152,210) |
| Credited (charged) to earnings | (85,400) | — | — | 3,307 | (82,093) |
| Credited (charged) to equity | — | — | — | 5,806 | 5,806 |
| Balance as at December 31, 2017 | $ (1,227,824) | $ — | $ — | $ (673) | $ (1,228,497) |
| Credited (charged) to earnings | 72,127 | (25,035) | (14,949) | 673 | 32,816 |
| **Balance as at December 31, 2018** | **$ (1,155,697)** | **$ (25,035)** | **$ (14,949)** | **$ —** | **$ (1,195,681)** |

As at December 31, 2018, the Corporation had approximately $7.7 billion in available tax pools (December 31, 2017 - $8.4 billion). Included in the tax pools are $5.1 billion of non-capital loss carry forward balances expiring as follows: $0.2 billion in 2026; $0.2 billion in 2027; $0.3 billion in 2028; $0.5 billion in 2029; $0.2 billion in 2030 and $3.7 billion after 2030. In addition, as at December 31, 2018, the Corporation had an additional $73 million (December 31, 2017 - $6.0 million) of capital investment in incomplete projects which will serve to increase available tax pools upon completion of the projects. As at December 31, 2018, the Corporation had not recognized the tax benefit related to $0.4 billion of realized and unrealized taxable capital foreign exchange losses (December 31, 2017 - $0.4 billion).

## 15. SHARE CAPITAL

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

Changes in issued common shares are as follows:

| Year ended December 31 | 2018 | | 2017 | |
|---|---|---|---|---|
| | Number of shares (thousands) | Amount | Number of shares (thousands) | Amount |
| Balance, beginning of year | **294,104** | **$ 5,403,978** | 226,467 | $ 4,878,607 |
| Shares issued | **—** | **—** | 66,815 | 517,816 |
| Share issue costs net of tax | **—** | **—** | — | (15,698) |
| Issued upon exercise of stock options | **212** | **1,813** | — | — |
| Issued upon vesting and release of RSUs and PSUs | **2,525** | **21,232** | 822 | 23,253 |
| Balance, end of year | **296,841** | **$ 5,427,023** | 294,104 | $ 5,403,978 |

On January 27, 2017, the Corporation issued 66,815,000 common shares at a price of $7.75 per share for gross proceeds of $517.8 million.

## 16. STOCK-BASED COMPENSATION

The Corporation has a number of stock-based compensation plans which include stock options, restricted share units ("RSUs"), performance share units ("PSUs") and deferred share units ("DSUs"). Further detail on each of these plans is outlined below.

a. Cash-settled plans

i. Restricted share units and performance share units:

RSUs granted under the cash-settled RSU plan generally vest annually in thirds over a three-year period. PSUs granted under the cash-settled RSU plan generally vest on the third anniversary of the grant date, provided that the Corporation satisfies certain performance criteria identified by the Corporation's Board of Directors within a target range and which are set and measured annually. The stock-based compensation expense for PSUs is determined based on an estimate of the final number of PSU awards that eventually vest based on the performance multiplier and the performance criteria.

Cash-settled RSUs and PSUs outstanding:

| Year ended December 31 (expressed in thousands) | 2018 | 2017 |
|---|---|---|
| Outstanding, beginning of year | **5,310** | 6,013 |
| Granted | **467** | 1,455 |
| Vested and released | **(1,397)** | (1,467) |
| Forfeited | **(118)** | (691) |
| Outstanding, end of year | **4,262** | 5,310 |

ii. Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of DSUs to directors of the Corporation. A DSU represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares purchased through a broker. DSUs vest immediately when granted and are redeemed on the third business day following the date on which the holder ceases to be a director. As at December 31, 2018, there were 342,775 DSUs outstanding (December 31, 2017 – 284,871 DSUs outstanding).

As at December 31, 2018, the Corporation has recognized a liability of $30.4 million relating to the fair value of cash-settled RSUs, PSUs and DSUs (December 31, 2017 – $14.3 million). The current portion of $22.0 million is included within accounts payable and accrued liabilities and $8.4 million is included as a non-current liability within provisions and other liabilities based on the expected payout dates of the individual awards.

b. Equity-settled plans

i. Stock options outstanding:

The Corporation's Stock Option Plan allows for the granting of stock options to directors, officers, employees and consultants of the Corporation. Stock options granted are generally fully exercisable after three years and expire seven years after the grant date.

| Year ended December 31 | 2018 | | 2017 | |
|---|---|---|---|---|
| | Stock options (thousands) | Weighted average exercise price | Stock options (thousands) | Weighted average exercise price |
| Outstanding, beginning of year | **8,896** | **$ 23.81** | 9,281 | $ 27.45 |
| Granted | **798** | **9.03** | 1,212 | 4.57 |
| Exercised | **(212)** | **5.77** | — | — |
| Forfeited | **(439)** | **22.64** | (927) | 27.78 |
| Expired | **(526)** | **50.70** | (670) | 33.81 |
| Outstanding, end of year | **8,517** | **$ 21.27** | 8,896 | $ 23.81 |

| As at December 31, 2018 | Outstanding | | | Vested | | |
|---|---|---|---|---|---|---|
| Range of exercise prices | Options (thousands) | Weighted average exercise price | Weighted average remaining life (in years) | Options (thousands) | Weighted average exercise price | Weighted average remaining life (in years) |
| $4.53 - $10.00 | 2,760 | $ 6.37 | 5.39 | 923 | $ 5.84 | 4.83 |
| $10.01 - $30.00 | 2,280 | 18.57 | 3.44 | 2,280 | 18.57 | 3.44 |
| $30.01 - $46.38 | 3,477 | 34.87 | 1.53 | 3,477 | 34.87 | 1.53 |
| | **8,517** | **$ 21.27** | **3.29** | **6,680** | **$ 25.30** | **2.64** |

The fair value of each option granted during the years ended December 31, 2018 and 2017 was estimated on the date of the grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

| **Year ended December 31** | | **2018** | | **2017** |
|---|---|---|---|---|
| Risk-free rate | | **2.17%** | | 1.14% |
| Expected lives | | **5 years** | | 5 years |
| Volatility[(i)] | | **62%** | | 59% |
| Annual dividend per share | | **nil** | | nil |
| Fair value of options granted | **$** | **4.82** | $ | 2.11 |

*(i) Expected volatility is determined by the average price volatility of the Corporation's common shares over the past five years.*

ii. Restricted share units and performance share units:

RSUs granted under the equity-settled Restricted Share Unit Plan generally vest annually in thirds over a three-year period. PSUs granted under the equity-settled Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that the Corporation satisfies certain performance criteria identified by the Corporation's Board of Directors within a target range and which are set and measured annually.

Equity-settled RSUs and PSUs outstanding:

| **Year ended December 31**<br>(expressed in thousands) | **2018** | **2017** |
|---|---|---|
| Outstanding, beginning of year | **6,308** | 1,656 |
| Granted | **3,273** | 5,757 |
| Vested and released | **(2,532)** | (823) |
| Forfeited | **(515)** | (282) |
| Outstanding, end of year | **6,534** | 6,308 |

c. Stock-based compensation

| **Year ended December 31** | | **2018** | | **2017** |
|---|---|---|---|---|
| Cash-settled expense [(i)] | **$** | **25,539** | $ | 3,476 |
| Equity-settled expense | | **21,584** | | 19,052 |
| Stock-based compensation | **$** | **47,123** | $ | 22,528 |

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

## 17. REVENUES

| Year ended December 31 | | 2018 | | 2017 Revised (Note 3) |
|---|---|---|---|---|
| Petroleum revenue[(i)] | | | | |
| Proprietary | $ | 2,502,524 | $ | 2,208,577 |
| Third-party[(ii)] | | 208,526 | | 253,486 |
| Petroleum revenue | | 2,711,050 | | 2,462,063 |
| Royalties | | (38,205) | | (22,578) |
| Petroleum revenue, net of royalties | $ | 2,672,845 | $ | 2,439,485 |
| Power revenue | $ | 47,879 | $ | 22,209 |
| Transportation revenue | | 11,980 | | 12,801 |
| Other revenue | $ | 59,859 | $ | 35,010 |
| | | | | |
| | $ | 2,732,704 | $ | 2,474,495 |

(i) *The Corporation had two major customers each with revenue in excess of 10% of total petroleum revenue. Sales to major customers totaled $1.0 billion for the year ended December 31, 2018 (year ended December 31, 2017 - $0.9 billion).*

(ii) *The Corporation purchases crude oil products from third parties for marketing-related activities. These purchases are included in the consolidated statement of earnings (loss) and comprehensive income (loss) under the caption "Purchased product".*

a. Disaggregation of revenue from contracts with customers

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

| | Year ended December 31 | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2018 | | | | | | 2017 | | | | | |
| | Petroleum Revenue | | | | | | Petroleum Revenue | | | | | |
| | | Proprietary | | Third-party | | Total | | Proprietary | | Third-party | | Total |
| Country: | | | | | | | | | | | | |
| Canada | $ | 1,434,655 | $ | 96,390 | $ | 1,531,045 | $ | 1,262,722 | $ | 147,498 | $ | 1,410,220 |
| United States | | 1,067,869 | | 112,136 | | 1,180,005 | | 945,855 | | 105,988 | | 1,051,843 |
| | $ | 2,502,524 | $ | 208,526 | $ | 2,711,050 | $ | 2,208,577 | $ | 253,486 | $ | 2,462,063 |

Other revenue recognized during the years ended December 31, 2018 and 2017 is attributed to Canada.

b. Revenue-related assets

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

| As at | | December 31, 2018 | | December 31, 2017 |
|---|---|---|---|---|
| Petroleum revenue | $ | 121,928 | $ | 244,330 |
| Other revenue | | 4,489 | | 2,960 |
| Total revenue-related assets | $ | 126,417 | $ | 247,290 |

Revenue-related receivables are typically settled within 30 days. As at December 31, 2018 and December 31, 2017, no impairment has been recognized on revenue-related receivables.

## 18. DILUENT AND TRANSPORTATION

| Year ended December 31 | 2018 | 2017 |
|---|---|---|
| Diluent expense | $ 1,281,075 | $ 944,134 |
| Transportation expense[a] | 279,603 | 214,280 |
| Diluent and transportation | $ 1,560,678 | $ 1,158,414 |

a. On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline. Transportation expense includes incremental expenses associated with the related Transportation Services Agreement from March 22, 2018 through December 31, 2018.

## 19. PURCHASED PRODUCT

| Year ended December 31 | 2018 | 2017 |
|---|---|---|
| | | Revised (Note 3) |
| Third-party purchased product | $ 194,564 | $ 250,681 |
| Blend purchases | 69,695 | 39,975 |
| Purchased product[i] | $ 264,259 | $ 290,656 |

*(i) The Corporation purchases crude oil products from third-parties for marketing-related activities.*

## 20. FOREIGN EXCHANGE LOSS (GAIN), NET

| Year ended December 31 | 2018 | 2017 |
|---|---|---|
| Unrealized foreign exchange loss (gain) on: | | |
| Long-term debt | $ 345,542 | $ (343,633) |
| Other | (4,789) | 5,489 |
| Unrealized net loss (gain) on foreign exchange | 340,753 | (338,144) |
| Realized loss (gain) on foreign exchange | 5,771 | (4,403) |
| Realized loss (gain) on foreign exchange derivatives[a] | (35,362) | — |
| Foreign exchange loss (gain), net | $ 311,162 | $ (342,547) |

| C$ equivalent of 1 US$ | | |
|---|---|---|
| Beginning of year | 1.2518 | 1.3427 |
| End of year | 1.3646 | 1.2518 |

a. On February 8, 2018, the Corporation entered into forward currency contracts to manage the foreign exchange risk on expected Canadian dollar denominated asset sale proceeds designated for U.S. dollar denominated long-term debt repayment. The forward currency contracts were settled on March 22, 2018, resulting in a realized gain of $35.4 million.

## 21. NET FINANCE EXPENSE

| Year ended December 31 | | 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[(a)] | | **—** | | 30,801 |
| Accretion on provisions | | **7,637** | | 7,760 |
| Unrealized loss (gain) on derivative financial liabilities | | **3,096** | | (16,179) |
| Realized loss (gain) on interest rate swaps[(b)] | | **(17,312)** | | 1,028 |
| Net finance expense | $ | **285,980** | $ | 361,080 |

a. During the first quarter of 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for proceeds of $1.52 billion (net of transaction costs of $18.5 million). A majority of the net proceeds were used to repay approximately $1.2 billion of the senior secured term loan (Note 12). The repayment of debt 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 at 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.

b. In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of its US$1.2 billion senior secured term loan at approximately 5.3%. In conjunction with the partial repayment of the senior secured term loan on March 27, 2018, the interest rate swap was terminated and a realized gain of $17.3 million was recognized.

## 22. OTHER EXPENSES

| Year ended December 31 | | 2018 | | 2017 |
|---|---|---|---|---|
| Defense costs related to unsolicited bid[(a)] | $ | **19,152** | $ | — |
| Severance and other | | **5,445** | | 4,948 |
| Onerous contracts expense[(b)] | | **3,296** | | 10,830 |
| Contract cancellation expense[(c)] | | **—** | | 18,765 |
| Other expenses | $ | **27,893** | $ | 34,543 |

a. 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. On October 17, 2018, the Corporation issued a Directors' Circular recommending shareholders to 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.

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

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

## 23. WAGES AND EMPLOYEE BENEFITS EXPENSE

| Year ended December 31 | | 2018 | | 2017 |
|---|---|---|---|---|
| Operating expense: | | | | |
| Salaries and wages(i) | **$** | **55,414** | $ | 48,574 |
| Short-term employee benefits | | **5,746** | | 5,454 |
| General and administrative expense: | | | | |
| Salaries and wages(i) | | **56,549** | | 58,806 |
| Short-term employee benefits | | **8,672** | | 9,047 |
| | **$** | **126,381** | $ | 121,881 |

*(i) Excludes severance included in other expenses (Note 22).*

## 24. TRANSACTIONS WITH RELATED PARTIES

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

| Year ended December 31 | | 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 |

## 25. SUPPLEMENTAL CASH FLOW DISCLOSURES

| Year ended December 31 | | 2018 | | 2017 |
|---|---|---|---|---|
| Cash provided by (used in): | | | | |
| Trade receivables and other | $ | **79,698** | $ | (52,074) |
| Inventories | | **(4,568)** | | (19,591) |
| Accounts payable and accrued liabilities | | **9,763** | | 123,380 |
| | $ | **84,893** | $ | 51,715 |
| Changes in non-cash working capital relating to: | | | | |
| Operating | $ | **111,291** | $ | (24,517) |
| Investing | | **(26,398)** | | 76,232 |
| | $ | **84,893** | $ | 51,715 |
| Cash and cash equivalents:[(a)] | | | | |
| Cash | $ | **276,810** | $ | 276,023 |
| Cash equivalents | | **40,894** | | 187,508 |
| | $ | **317,704** | $ | 463,531 |
| Cash interest paid | $ | **252,207** | $ | 294,743 |

a. As at December 31, 2018, C$154.2 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (December 31, 2017 – C$201.0 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the year end exchange rate of US$1 = C$1.3646 (December 31, 2017 – US$1 = C$1.2518).

The following table reconciles long-term debt to cash flows arising from financing activities:

| | | Long-term debt [i] |
|---|---|---|
| Balance as at December 31, 2016 | $ | 5,070,694 |
| Cash changes: | | |
| Debt refinancing costs | | (61,930) |
| Redemption of senior unsecured notes | | (1,008,825) |
| Issue of senior secured second lien notes | | 1,008,825 |
| Payments on term loan | | (12,690) |
| Non-cash changes: | | |
| Unrealized loss (gain) on foreign exchange | | (343,633) |
| Change in fair value of financial derivative liability | | (10,426) |
| Debt extinguishment expense | | 30,801 |
| Amortization of financial derivative liability discount | | 3,520 |
| Amortization of deferred debt discount and debt issue costs | | 7,391 |
| Balance as at December 31, 2017 | $ | 4,683,727 |
| Cash changes: | | |
| Payments on term loan | | (1,284,855) |
| Non-cash changes: | | |
| Unrealized loss (gain) on foreign exchange | | 345,542 |
| Amortization of financial derivative liability discount | | 882 |
| Amortization of deferred debt discount and debt issue costs | | 5,325 |
| IFRS 9 adjustment to deferred debt discount and debt issue costs (Note 3) | | 6,381 |
| **Balance as at December 31, 2018** | **$** | **3,757,002** |

*(i) Long-term debt, including the current portion of long-term debt.*

## 26. NET EARNINGS (LOSS) PER COMMON SHARE

| **Year ended December 31** | | **2018** | | **2017** |
|---|---|---|---|---|
| Net earnings (loss) | **$** | **(119,197)** | $ | 165,976 |
| Weighted average common shares outstanding (thousands)[a] | | **295,740** | | 289,142 |
| Dilutive effect of stock options, RSUs and PSUs (thousands)[b] | | **—** | | 117 |
| Weighted average common shares outstanding – diluted (thousands) | | **295,740** | | 289,259 |
| Net earnings (loss) per share, basic | **$** | **(0.40)** | $ | 0.57 |
| Net earnings (loss) per share, diluted | **$** | **(0.40)** | $ | 0.57 |

a. Weighted average common shares outstanding for the year ended December 31, 2018 includes nil PSUs not yet released (year ended December 31, 2017 - 139,863 PSUs).

b. For the year ended December 31, 2018, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss. If the Corporation had recognized net earnings during the year ended December 31, 2018, the dilutive effect of stock options, RSUs and PSUs would have been 3.8 million weighted average common shares.

## 27. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments recognized on the consolidated balance sheet are comprised of cash and cash equivalents, trade receivables and other, commodity risk management contracts, the interest rate swap included within other assets, accounts payable and accrued liabilities, finance leases and derivative financial liabilities included within provisions and other liabilities and long-term debt. As at December 31, 2018, commodity risk management contracts were classified as fair value through profit and loss; cash and cash equivalents, trade receivables and other, accounts payable and accrued liabilities, finance leases and long-term debt were carried at amortized cost.

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

a. Fair value measurements of long-term debt, finance leases, derivative financial liabilities, commodity risk management contracts and the interest rate swap are as follows:

| | | Fair value measurements using | | |
|---|---|---|---|---|
| **As at December 31, 2018** | **Carrying amount** | **Level 1** | **Level 2** | **Level 3** |
| Recurring measurements: | | | | |
| Financial assets | | | | |
| Commodity risk management contracts | **$ 122,658** | **$ —** | **$ 122,658** | **$ —** |
| Financial liabilities | | | | |
| Long-term debt[(i)] (Note 12) | **$ 3,787,155** | **$ —** | **$ 3,706,647** | **$ —** |
| Finance leases (Note 13) | **$ 131,063** | **$ —** | **$ —** | **$ 131,063** |
| Derivative financial liabilities | **$ 1,058** | **$ —** | **$ 1,058** | **$ —** |
| Commodity risk management contracts | **$ 29,709** | **$ —** | **$ 29,709** | **$ —** |

| | | Fair value measurements using | | |
|---|---|---|---|---|
| **As at December 31, 2017** | **Carrying amount** | **Level 1** | **Level 2** | **Level 3** |
| Recurring measurements: | | | | |
| Financial assets | | | | |
| Interest rate swap (Note 10) | $ 8,067 | $ — | $ 8,067 | $ — |
| Financial liabilities | | | | |
| Long-term debt[(i)] (Note 12) | $ 4,726,468 | $ — | $ 4,415,238 | $ — |
| Derivative financial liabilities | $ 6,028 | $ — | $ 6,028 | $ — |
| Commodity risk management contracts | $ 68,649 | $ — | $ 68,649 | $ — |

*(i) Includes the current and non-current portions.*

Level 1 fair value measurements are based on unadjusted quoted market prices.

As at December 31, 2018, the Corporation did not have any financial instruments measured at Level 1 fair value.

Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted prices or indices.

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker.

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

Level 3 fair value measurements are based on unobservable information.

The estimated fair value of finance leases is based on recently observed transactions, or calculated by discounting the expected future contractual cash flows using a discount rate based on either contractual terms or market rates for instruments of similar maturity and credit risk.

The Corporation recognizes transfers into and transfers out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer.

b. Commodity price risk management:

The Corporation enters into derivative financial instruments to manage commodity price risk. The use of the financial commodity risk management contracts is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes. Financial commodity risk management contracts are measured at fair value, with gains and losses on re-measurement included in the consolidated statement of earnings and comprehensive income in the period in which they arise.

The Corporation 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)**[(i)] | **Term** | **Average Price (US$/bbl)**[(i)] |
|---|---|---|---|
| **Crude Oil Sales Contracts** | | | |
| Fixed Price: | | | |
| WTI[(ii)] Fixed Price | 21,115 | Jan 1, 2019 - Dec 31, 2019 | $67.30 |
| WTI:WCS[(iii)] 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 |

*(i) The volumes and prices in the above table 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.*

*(ii) West Texas Intermediate ("WTI") crude oil*

*(iii) Western Canadian Select ("WCS") crude oil blend*

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

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

| As at | December 31, 2018 | | | December 31, 2017 | | |
|---|---|---|---|---|---|---|
| | Asset | Liability | Net | Asset | Liability | Net |
| Gross amount | **$ 302,503** | **$ (65,863)** | **$ 236,640** | $ — | $ (184,175) | $ (184,175) |
| Amount offset | **(179,845 )** | **36,154** | **(143,691 )** | — | 115,526 | 115,526 |
| Net amount | **$ 122,658** | **$ (29,709)** | **$ 92,949** | $ — | $ (68,649) | $ (68,649) |
| | | | | | | |
| Current portion | **$ 122,658** | **$ (6,061)** | **$ 116,597** | $ — | $ (68,649) | $ (68,649) |
| Non-current portion | **—** | **(23,648 )** | **(23,648 )** | — | — | — |
| Net amount | **$ 122,658** | **$ (29,709)** | **$ 92,949** | $ — | $ (68,649) | $ (68,649) |

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

| As at December 31 | 2018 | 2017 |
|---|---|---|
| Fair value of contracts, beginning of year | $ (68,649) | $ (30,313) |
| Fair value of contracts realized | 138,902 | 11,273 |
| Change in fair value of contracts | 22,471 | (49,609) |
| Unamortized premiums on put and call options | 225 | — |
| Fair value of contracts, end of year | **$ 92,949** | $ (68,649) |

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

| Year ended December 31 | 2018 | 2017 |
|---|---|---|
| Realized loss (gain) on commodity risk management | **$ 138,902** | $ 11,273 |
| Unrealized loss (gain) on commodity risk management | **(161,373)** | 38,336 |
| Commodity risk management loss (gain) | **$ (22,471)** | $ 49,609 |

The following table summarizes the sensitivity of the earnings before income tax impact of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place as at December 31, 2018:

| Commodity | Sensitivity Range | Increase | Decrease |
|---|---|---|---|
| Crude oil commodity price | ± US$1.00 per bbl applied to WTI contracts | $ (10,517 ) | $ 10,517 |
| Crude oil differential price (i) | ± US$1.00 per bbl applied to WCS differential contracts | $ 17,937 | $ (17,937 ) |

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

The Corporation entered into the following financial commodity risk management contracts relating to crude oil sales subsequent to December 31, 2018. As a result, these contracts are not reflected in the Corporation's Consolidated Financial Statements:

| Subsequent to December 31, 2018 | Volumes (bbls/d) | Term | Average Prices (US$/bbl) |
|---|---|---|---|
| **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) |

c. Credit risk management:

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward looking information to determine the appropriate loss allowance provisions. Credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to each counterparty's credit quality. A substantial portion of accounts receivable are with investment grade customers in the energy industry and are subject to normal industry credit risk. The Corporation has experienced no material loss in relation to trade receivables. As at December 31, 2018, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $210.6 million.

The Corporation's cash balances are used to fund the development of its oil sands properties. As a result, the primary objectives of the investment portfolio are low risk capital preservation and high liquidity. The cash balances are held in high interest savings accounts or are invested in high grade, liquid, short-term instruments such as bankers' acceptances, commercial paper, money market deposits or similar instruments. The cash and cash equivalents balance at December 31, 2018 was $317.7 million. None of the investments are past their maturity or considered impaired. The Corporation's estimated maximum exposure to credit risk related to its cash and cash equivalents is $317.7 million.

d. 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 on long-term debt. In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of the US$1.2 billion senior secured term loan at approximately 5.3%. Interest rate swaps are classified as derivative financial assets and liabilities and measured at fair value, with gains and losses on re-measurement included as a component of net finance expense in the period in which they arise. In conjunction with the partial repayment of the senior secured term loan on March 27, 2018, the interest rate swap was terminated and a realized gain of $17.3 million was recognized (Note 21).

As at December 31, 2018, a 1% increase in the LIBOR on the floating rate debt would have resulted in a $6.1 million increase in net loss before income taxes (December 31, 2017 - $14.1 million decrease in net earnings before income taxes). As at December 31, 2018, a 1% decrease in LIBOR would have resulted in a $4.9 million decrease in net loss before income taxes (December 31, 2017 - $2.6 million increase in net earnings before income taxes).

e. Foreign currency risk management:

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the fair value or future cash flows of the Corporation's financial assets or liabilities. The Corporation has U.S. dollar denominated long-term debt as described in Note 12. As at December 31, 2018, a $0.01 change in the U.S. dollar to Canadian dollar exchange rate would have resulted in a corresponding change in the carrying value of long-term debt of C$27.8 million (December 31, 2017 - C$37.8 million).

f. Liquidity risk management:

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

The future undiscounted financial obligations of the Corporation are noted below:

| As at December 31, 2018 | Total | Less than 1 year | 1 - 3 years | 5 years | More than 5 years |
|---|---|---|---|---|---|
| Long-term debt | $ 3,787,155 | $ 16,852 | $ 33,704 | $ 1,348,636 | $ 2,387,963 |
| Interest on long-term debt | 1,267,457 | 249,254 | 495,551 | 426,707 | 95,945 |
| Commodity risk management contracts | 92,949 | 116,597 | (23,648) | — | — |
| Derivative financial liabilities | 1,058 | 19 | 356 | 683 | — |
| Accounts payable and accrued liabilities | 342,258 | 342,258 | — | — | — |
| | $ 5,490,877 | $ 724,980 | $ 505,963 | $ 1,776,026 | $ 2,483,908 |

| As at December 31, 2017 | Total | Less than 1 year | 1 - 3 years | 5 years | More than 5 years |
|---|---|---|---|---|---|
| Long-term debt | $ 4,726,468 | $ 15,460 | $ 30,920 | $ 30,920 | $ 4,649,168 |
| Interest on long-term debt | 1,769,714 | 292,046 | 581,682 | 578,464 | 317,522 |
| Commodity risk management contracts | 68,649 | 68,649 | — | — | — |
| Derivative financial liabilities | 6,028 | 90 | 1,048 | 3,210 | 1,680 |
| Accounts payable and accrued liabilities | 336,280 | 336,280 | — | — | — |
| | $ 6,907,139 | $ 712,525 | $ 613,650 | $ 612,594 | $ 4,968,370 |

## 28. GEOGRAPHICAL DISCLOSURE

As at December 31, 2018, the Corporation had non-current assets related to operations in the United States of $99.3 million (December 31, 2017 – $101.7 million). For the year ended December 31, 2018, petroleum revenue related to operations in the United States was $1.2 billion (year ended December 31, 2017 – $1.1 billion).

## 29. JOINT OPERATIONS

The Corporation transports its bitumen blend volumes and diluent purchases on pipelines that are operated by Access Pipeline. Up until March 22, 2018, the Corporation owned an undivided 50% working interest in this jointly controlled entity and presented its proportionate share of the assets, liabilities, revenues and expenses of the joint operation on a line-by-line basis in the December 31, 2017 consolidated financial statements. As at December 31, 2018, the Corporation's proportionate interest in the joint operation's working capital balances was $nil (December 31, 2017 - $2.4 million) and its interest in related pipeline assets, recorded in property, plant and equipment, was $nil (December 31, 2017 - $1.05 billion).

## 30. COMMITMENTS AND CONTINGENCIES

a. Commitments

The Corporation's commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at December 31, 2018:

| | 2019 | 2020 | 2021 | 2022 | 2023 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Transportation and storage(i) | $ 349,389 | $ 375,293 | $ 424,379 | $ 450,239 | $ 447,021 | $ 6,270,410 | $ 8,316,731 |
| Office lease rentals(ii) | 10,855 | 11,278 | 11,278 | 11,278 | 11,616 | 95,976 | 152,281 |
| Diluent purchases | 360,886 | 21,606 | 21,547 | 21,547 | 17,946 | — | 443,532 |
| Other operating commitments | 15,748 | 12,554 | 10,472 | 9,441 | 9,452 | 49,963 | 107,630 |
| Capital commitments | 5,708 | — | — | — | — | — | 5,708 |
| **Commitments** | **$ 742,586** | **$ 420,731** | **$ 467,676** | **$ 492,505** | **$ 486,035** | **$ 6,416,349** | **$ 9,025,882** |

*(i) This represents transportation and storage commitments from 2019 to 2048, including the Access Pipeline TSA, and various pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet (Note 13(a)).*

*(ii) Excludes amounts for which an onerous contracts provision has been recognized on the consolidated balance sheet (Note 13(b)).*

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.

## 31. CAPITAL DISCLOSURES

The Corporation's capital structure consists of shareholders' equity and long-term debt. The Corporation's objective when managing its capital structure is to maintain financial flexibility that will allow it to execute future capital development projects, preserve access to funding, generate sufficient internally generated cash flow, retain its ability to meet financial obligations as they come due, and position the Corporation for strategic expansion and growth opportunities. The Corporation manages its capital structure in response to changing economic conditions and is able to adjust capital and operating spending, sell assets, issue new common shares, issue new debt, draw down on its revolving credit facility, or repay existing debt.

As at December 31, 2018, the Corporation's capital resources included $289.8 million of working capital, an additional undrawn US$1.4 billion syndicated revolving credit facility and a US$440.0 million guaranteed letter of credit facility under which US$298.9 million of letters of credit have been issued. Working capital is comprised of $317.7 million of cash and cash equivalents, offset by a non-cash working capital deficiency of $27.9 million.

The Corporation's cash is held in high interest savings accounts with a group of highly-rated financial institutions. The Corporation has also invested in high grade, liquid, short-term instruments such as bankers' acceptances, commercial paper, money market deposits or similar instruments. To date, 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 policy 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.