MEG Energy

A New Approach to the Oil Sands

2017
ANNUAL REPORT

MEG Energy Corp.

is a Canadian energy company focused on sustainable in situ development and production in the southern Athabasca oil sands region of Alberta.

We are using our proven, proprietary technology to dramatically reduce our energy and water use, capital and operating costs, development time frame and greenhouse gas intensity.

Driven by innovation, MEG is creating a paradigm shift in the possibilities for operations, growth and sustainability in the oil sands.

2017 ANNUAL REPORT

To Our Shareholders

A MESSAGE FROM THE PRESIDENT AND CEO

WE TITLED OUR 2017 ANNUAL REPORT "A NEW APPROACH TO THE OIL SANDS" BECAUSE WE WANTED TO HIGHLIGHT HOW TECHNOLOGY HAS TRANSFORMED OUR BUSINESS OVER THE PAST FEW YEARS. THE OLD STEREOTYPE OF AN OIL SANDS OPERATOR AS A HIGH COST, HIGH EMITTER IS NO LONGER RELEVANT.

This new approach, however, did not happen overnight. It was the result of a series of calculated decisions that were made a few years ago. In late 2014 to early 2015, the oil industry went through a major upheaval as commodity prices had dropped substantially and became very volatile when OPEC changed its focus from price protection to preserving market share. This was a major change for producers after more than a decade of high commodity prices where it was very economic to grow.

It quickly became apparent that the old way of doing business was no longer going to work. We needed a fresh approach that would enable us to:

1) Reduce the overall costs of doing business,

2) Grow in a more sustainable and continuous fashion at lower capital cost intensities given the anticipated volatility in future commodity prices, and

3) Address our balance sheet in light of the new commodity pricing environment.

I am pleased to report that significant progress has been made on all these initiatives.

REDUCING THE COSTS OF DOING BUSINESS

Two key areas that are within our control are non-energy operating costs and administration costs. In both cases these indicators are down considerably. Since 2014, our per barrel non-energy operating and general and administrative costs have been reduced by 40% and 30% respectively. The notion of oil sands being a high cost producer is a thing of the past, as we can now produce a barrel of oil with operating costs of $7.00 or less.

MORE FLEXIBLE GROWTH AT REDUCED CAPITAL COST INTENSITIES

The application of technology is enabling us to move away from large scale growth projects to more flexible growth on a continuous basis. This is the area of the business that I am most excited about. In the areas where we have deployed our proprietary reservoir technologies we have seen the steam-to-oil ratio, a key measure of energy efficiency, also reduced by roughly 50%. This in turn has significantly lowered our GHG emissions intensity as we continue to reduce our environmental footprint. The environmental benefits from our technology are an aspect of MEG's oil sands operations that has not been widely appreciated, but which we expect to see gaining more attention as the transition to a lower-carbon economy continues.

We have been deploying our patented technology known as "enhanced Modified Steam and Gas Push", or eMSAGP, since 2011. Essentially, we are able to significantly lower the amount of steam (energy) we use during production by harnessing residual heat in the reservoir and introducing a combination of trace amounts of natural gas with reduced amounts of steam into the process. We have implemented this technology on Phases 1 and 2 of our operations, with the steam-to-oil ratio dropping from the ~2.5 barrels of steam previously required to produce a barrel of bitumen all the way down to the 1.2 range.

Our future growth utilizes a combination of our proprietary reservoir technology which enables us to increase production and a series of smaller facility expansions to accommodate higher levels of bitumen. Our growth has a high level of flexibility because it allows us to adapt our pace of growth to changing market conditions.

Technology has also helped reduce the capital intensities required for our growth to as much as one half. The application of eMSAGP to our Phase 2B producing wells which we are currently undertaking comes at a cost of about $17,500 per flowing barrel. This is in direct contrast to the capital intensity required to complete large scale projects in the past, which was in excess of $40,000 per flowing barrel. Clearly technology is allowing our growth to be more flexible at a reduced capital intensity. It helps us to grow using cash flow at lower prices while also enabling MEG to speed up or slow down the pace of development based on market conditions.

NORMALIZING THE BALANCE SHEET

We developed a four-part strategy to address the leverage on the balance sheet.

> "The application of technology is enabling us to move away from large-scale growth projects to more flexible growth on a continuous basis. This is the area of the business that I am most excited about."

It included:

1) Refinancing and extending near term maturities to give us the time we needed to improve our balance sheet,
2) Implementing our fully funded highly economic growth projects which will enable us to grow into our debt,
3) Paying down a portion of our debt through the monetization of the Access Pipeline and Stonefell Terminal, and
4) Maximizing the revenue from every barrel we produce. There are significant benefits for MEG in targeting world prices to maximize cash flows and improve our debt metrics. In 2020, our capacity on the Flanagan/Seaway pipeline system will increase to 100,000 bpd of blend. At 113,000 bpd of bitumen (163,000 bpd blend), MEG will be selling almost two-thirds of its blend sales volume into the Gulf Coast.

In January 2017 we refinanced a portion of our balance sheet, maintaining a significant amount of liquidity while pushing out our earliest outstanding debt maturity to 2023. In addition, $518 million of equity capital was raised and a portion of the proceeds used to finance our highly economic eMSAGP growth which will add 20,000 bpd by early 2019, bringing production to 100,000 bpd.

Early in 2018 we monetized our 50% ownership of the Access Pipeline along with our Stonefell Terminal for $1.6 billion, which has also had a substantial impact on reducing our debt and allowed us to finance our brownfield expansion at Phase 2B, which will add a further 13,000 bpd in 2020. These transactions provided the flexibility and financial resources for MEG to continue the implementation of our plan.

The added volumes from the Phase 2B eMSAGP and brownfield projects will enable MEG to spread our fixed costs over more barrels and reduce our cash costs per barrel, strengthening our balance sheet in a volatile price environment.

When our two growth projects are completed, bringing our production to approximately 113,000 bpd, and with the sale of our Access Pipeline and Stonefell Terminal interests, we project our debt to EBITDA to be in a very acceptable range.

We have also been able to handle the recent pipeline apportionment issues facing our business by utilizing the network of storage tanks and rail facilities we have available to us. We continue to have good access to the U.S. Gulf Coast which enables us to send more marketable barrels south to access world prices.

We believe we have set the business on a very firm footing. By 2020 we want to have right-sized our balance sheet, built an even more sustainable company by reducing our breakeven to less than approximately US$40 per barrel WTI, chosen the technology which will propel us forward to 210,000 bpd, maximized the revenue we will get from every barrel by increasing our capacity to get crude to the Gulf Coast, and adapted our business model to the changing needs of the equity markets.

Our plan has put MEG in a very strong position for the future, which is why I'm now comfortable announcing my retirement as President and CEO as of June 1, 2018.

Although there is never a perfect time for a CEO transition, I believe this is the right time for me personally and for the company. It's a top priority for us to ensure a very smooth transition to a new CEO who will continue to help MEG reach its true potential.

I am very proud to have co-founded this Alberta-based company 19 years ago. I've learned a lot along the way and have had the opportunity to work with an extremely talented team at MEG.

Going forward, with the highly economic growth projects available to us, and the benefits that come from the use of advanced technology, we think MEG truly is "A New Approach to the Oil Sands".

Bill McCaffrey

Bill McCaffrey
President and CEO


AN OUTSTANDING 2017

Operational and Financial Highlights

($ millions, except as indicated)	2017	2016	2015	2014	2013
Bitumen production (barrels per day)	**80,774**	81,245	80,025	71,186	35,317
Bitumen realization ($ per barrel)	**41.89**	27.79	30.63	62.67	49.28
Steam-oil ratio (SOR)	**2.3**	2.3	2.5	2.5	2.6
Net operating costs ($ per barrel) [1]	**6.84**	7.99	9.39	12.06	10.01
Non-energy operating costs ($ per barrel)	**4.62**	5.62	6.54	8.02	9.00
Cash operating netback ($ per barrel) [2]	**27.00**	13.13	15.72	44.87	35.87
Adjusted funds flow from (used in) operations [3]	**373.8**	(61.6)	49.5	791.5	253.4
Per share, diluted [3]	**1.29**	(0.27)	0.22	3.52	1.13
Operating earnings (loss) [3]	**(113.5)**	(455.1)	(374.4)	247.4	0.4
Per share, diluted [3]	**(0.39)**	(2.01)	(1.67)	1.10	–
Revenue [4]	**2,434.7**	1,866.3	1,925.9	2,830.0	1,334.5
Net earnings (loss)	**166.0**	(428.7)	(1,169.7)	(105.5)	(166.4)
Per share, diluted	**0.57**	(1.90)	(5.21)	(0.47)	(0.75)
Total cash capital investment	**502.8**	137.2	257.2	1,237.5	2,111.8
Cash and cash equivalents	**463.5**	156.2	408.2	656.1	1,179.1
Long-term debt	**4,668.3**	5,053.2	5,190.4	4,350.4	3,990.7

(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, 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 from (used in) operations, 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 from (used in) operations 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 under the heading "NON-GAAP MEASURES" and discussed further in the "ADVISORY" section within the "MANAGEMENT'S DISCUSSION AND ANALYSIS" of this report.

(4) The total of Petroleum revenue, net of royalties and Other revenue as presented on the Consolidated Statement of Earnings and Comprehensive Income.

A New Approach to the Oil Sands Business Model

MEG ENERGY'S PROPRIETARY, PROVEN TECHNOLOGY HAS CHANGED THE WAY BUSINESS CAN BE DONE IN THE OIL SANDS

In an industry formerly driven by large scale growth projects that could take years to implement, we are using innovation to evolve to a low-cost, continuous growth model where projects can go from initial investment to cash flow in as little as 12 to 18 months. MEG can now plan, fund, build, bring on-stream and realize a return on investment on projects in an ongoing cycle of highly economic growth while reducing our costs, steam-oil ratio and greenhouse gas intensity.

TECHNOLOGY ENABLES INCREASED PRODUCTION, REDUCED STEAM

MEG's innovative business model is driven by our groundbreaking reservoir technologies which optimize process efficiency and cut the need for steam to heat and maintain pressure in the reservoir. Where employed, eMSAGP has reduced MEG's steam-oil ratio by about 50% to the 1.2 range, while decreasing greenhouse gas emission intensity to below the in situ industry average. Less steam for a given amount of bitumen produced also means less water used in MEG's operations.

The steam which is freed up by eMSAGP is then redeployed to new well pairs. This enables the company to increase production while at the same time significantly reducing steam and water handling upgrades to our central plant. The result is lower capital intensities and greater ability to focus the required capital spending on the drilling and tie-in of new wells.

MEG is also testing the company's proprietary eMVAPEX technology. A modification of its eMSAGP technology, eMVAPEX has the potential to further decrease MEG's steam-oil ratio beyond what eMSAGP can achieve, reduce future capital costs, and further decrease operating costs and greenhouse gas emission intensities. Initial tests in 2017 on eMVAPEX saw encouraging results, and in 2018 MEG plans to convert up to seven additional well pairs and associated infills to the process, as well as build a solvent recycling facility to test the commerciality and scalability of the process.

HIGHER OPERATING AND CAPITAL COST EFFICIENCY

eMSAGP, along with a strong focus on efficiency gains and continued cost management, is enabling the company to reduce costs as we grow production at a very attractive capital efficiency. In 2017, MEG posted record lows in annual non-energy operating costs of $4.62 per barrel and net operating costs of $6.84 per barrel. Our non-energy operating costs have been reduced by 55% since 2011 and have the potential to be reduced even further as we continue to implement eMSAGP at Phase 2B.

The Phase 2B brownfield expansion, which is anticipated to add an additional 13,000 barrels per day of production by early 2020, will drive our per barrel cash costs even lower.

Our growth going forward is also tremendously flexible in terms of the pace at which it can be implemented. MEG can expand it across a number of pads at one time or proceed more carefully on a pad by pad basis and possibly a well by well basis, which increases our ability to respond quickly and efficiently to market conditions.

HIGHLY-ECONOMIC GROWTH IN 2018 AND BEYOND

MEG's capital program for 2018 includes the completion of the eMSAGP growth initiative at Christina Lake Phase 2B, the expansion of our eMVAPEX test program, and the commencement of the company's 2B brownfield expansion project. MEG's growth to 113,000 bpd is fully-funded through cash on hand, anticipated cash flow, and a portion of the proceeds from the sale of the company's interest in the Access Pipeline and Stonefell Terminal.

In 2020, we anticipate that our debt to EBITDA will come into an acceptable range while generating free cash flow at current prices and supporting a sustainable level of growth.

IMPACT OF TECHNOLOGY ON MEG'S BUSINESS MODEL

Lower capital costs + Reduced development time frame + Reduced costs + Lower SOR and GHG intensity = HIGH RETURNS

Lower capital costs
$40k per flowing barrel
reduced to
$19k per flowing barrel
up to
113 kbpd

Reduced development time frame
3 to 4 years
reduced to
12 to 18 months

Reduced costs
55%
reduction in non-energy operating costs since 2011

Lower SOR and GHG intensity
SOR
reduction through proprietary technologies
Directly proportional reduction in GHG intensity and lower energy costs

HIGH RETURNS
40% to 50%
IRR @
$55 WTI

MEG Energy Sells Interest in Access Pipeline and Stonefell Terminal

$1.61 BILLION TRANSACTION OPENS A NEW CHAPTER FOR MEG ENERGY

On March 22, 2018, MEG closed a transaction that has substantially improved the company's financial position while ensuring our transportation and storage needs are met for decades going forward. An agreement with Wolf Midstream Inc. resulted in the sale of MEG's 50% interest in Access Pipeline and 100% interest in Stonefell Terminal for cash and other consideration of $1.61 billion, representing 13.4x 2018 annualized EBITDA.


Stonefell Terminal

MAINTAINING ACCESS TO KEY MARKETS

As part of the transaction, MEG has entered agreements securing access for our Christina Lake production and condensate transport for an initial term of 30 years, the right to use Access Pipeline's unutilized 16" pipe upon conversion to transport natural gas liquids on a long-term basis to support the eMVAPEX process, and a 30-year arrangement for operational control and continued use of Stonefell's 900,000 barrel blend and condensate storage facility.

UNLOCKING THE VALUE OF MEG'S MIDSTREAM ASSETS

MEG utilized the net proceeds from the transaction to repay $1.225 billion of the company's senior secured term loan and to fund the $275 million expansion at the company's Phase 2B facility. MEG has the financial resources in place to fund the company's growth all the way to 113,000 bpd by early 2020.

The brownfield expansion includes the addition of incremental steam capacity at the Phase 2B facility and two well pads and is expected to generate returns of approximately 30% at current prices. Production is anticipated to begin ramping up in the second half of 2019 to reach the full brownfield expansion capacity of 13,000 bpd in 2020.

As a result of the sale, MEG expects our net cash costs to increase by approximately $50 million per year. This includes an increase in transportation and storage costs of approximately $120 million per year, offset by a reduction in interest costs of approximately $70 million annually. This will be more than offset by MEG's ability to spread our fixed costs over the added barrels that come from the growth which is funded by the sale.

Assets sold for cash and other consideration

$1.61 billion

PROCEEDS ARE FUNDING:

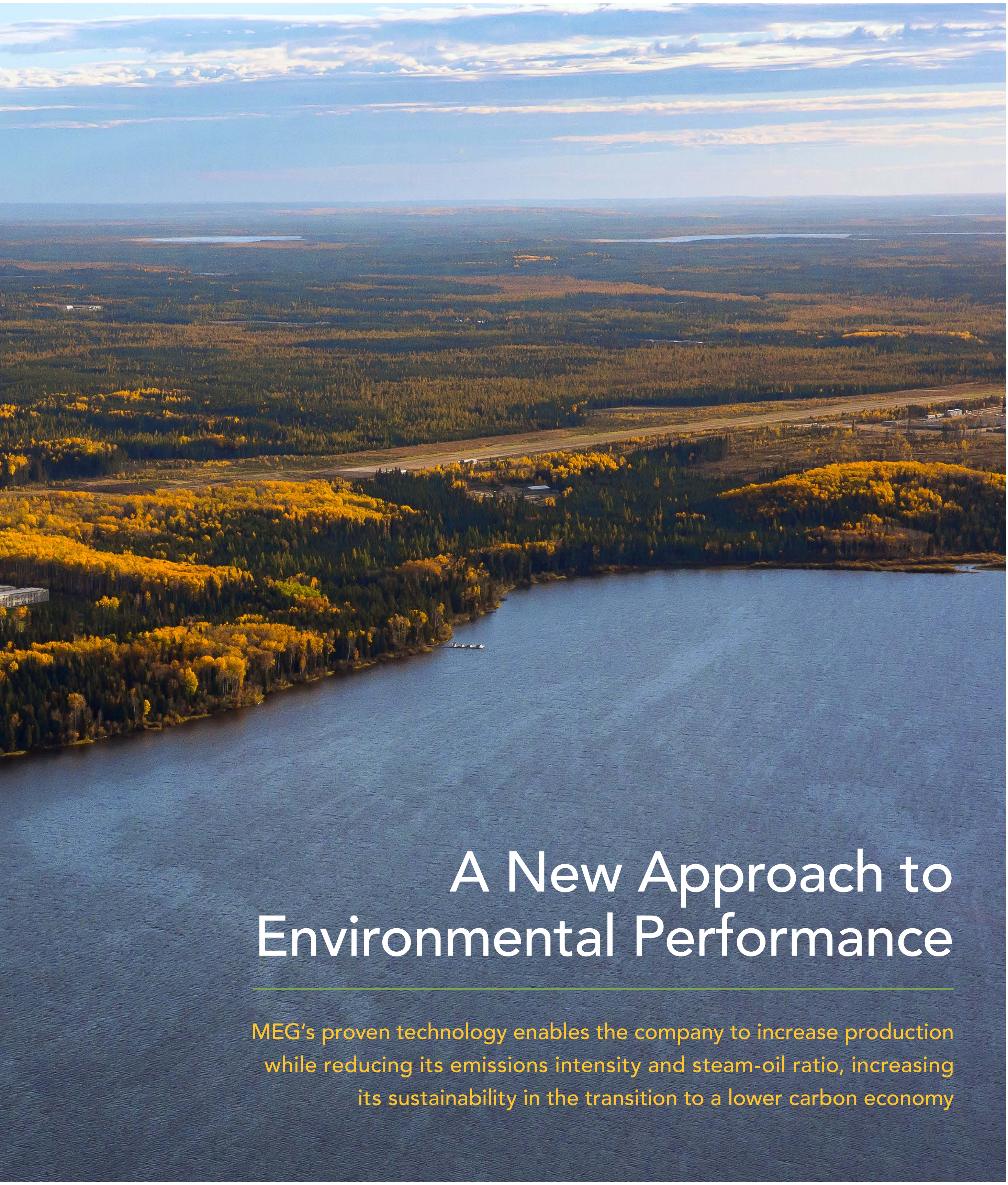
Term loan repayment

$1.225 billion

Phase 2B Brownfield Expansion over 2018 and 2019

$275 million

plus transaction fees and credit for future expansion of the Access Pipeline



A New Approach to Environmental Performance

MEG's proven technology enables the company to increase production while reducing its emissions intensity and steam-oil ratio, increasing its sustainability in the transition to a lower carbon economy


MEG ENERGY
MEG's Board of Directors, staff and contractors are committed to being exemplary stewards of the environment, ensuring our operations meet or exceed environmental standards and achieve excellence in health and safety

Environmental Stewardship

MEG'S CORPORATE STRATEGY, POLICIES AND PEOPLE ARE FOCUSED ON ENVIRONMENTAL INNOVATION AND EXCELLENCE

Our focus on technology and innovation has enabled MEG to reduce greenhouse gas (GHG) emissions intensity and water use intensity to one of the lowest in the industry, cut the amount of steam required to produce a barrel of oil by nearly half, and provide cleaner power to Alberta's energy grid.

As we continue to implement our proprietary eMSAGP technology and test our new eMVAPEX process, we anticipate being able to continuously improve our performance and reduce our environmental impact.

ENVIRONMENT, HEALTH AND SAFETY MANAGEMENT OVERSIGHT

MEG's Board of Directors is responsible for verifying that MEG sets high environmental standards, is in compliance with environmental laws and regulations, and has key programs and policies in place for the health and safety of its employees in the workplace. The Board reviews and approves corporate strategies to mitigate environment, health and safety (EHS) risks including climate change.

The Board also establishes annual safety performance targets that, in part, drive management compensation. MEG has also recently added environmental performance targets for spills and GHG intensity.

ENVIRONMENTAL PLANNING

MEG uses a value-driven Enterprise Risk Management (ERM) system to create and protect value and to address uncertainty. ERM is integrated into existing processes within the company including strategic planning, business planning, operating practices, marketing, compliance monitoring, operating performance measurement and facility design. MEG incorporates EHS considerations into all phases of our projects in order to effectively manage risks that develop over time. Identified risks are evaluated on impact severity and likelihood of occurrence, based on the current business and political environment. Risks are quantified and prioritized and risk mitigation strategies are updated by management and reviewed by MEG's Board of Directors.

ENVIRONMENT, HEALTH AND SAFETY MANAGEMENT PERFORMANCE PROGRAM

MEG's integrated Environmental, Health and Safety Management System has been in place since 2006 and was updated in 2015 to reflect changes in the growth and scope of the company. The EHS Management Performance Program aligns with both ISO 14001 and Certificate of Recognition Safety program components. The purpose of the program is to effectively manage and continuously improve MEG's environmental, health and safety program and performance. It outlines corporate requirements in 10 focus areas: Organization Commitment & Management Review, Program Administration, Objectives and Targets, Hazard/Risk Assessment, Hazard/Risk Control, Qualifications, Orientations and Training, Monitoring and Measuring, Contractor Management, Emergency Response Planning, and Incident Investigation and Management.

Managing Climate Risk

MEG IS ADOPTING A SYSTEMATIC APPROACH TO ADDRESSING CLIMATE RISK ACROSS OUR ORGANIZATION

MEG has built a strategy that allows us to objectively assess our business model against an ever-changing landscape of financial, legal and stakeholder pressures. Our goal is to find the business opportunities to strengthen economic outcomes, promote technology advancements and demonstrate resiliency where there may be regulatory uncertainty. We are working to continue gathering and sharing thorough, accurate information and broadening the communications networks available to the company and our stakeholders. This work is key to identifying information that is relevant and useful, and ensuring it gets to the people who require it.

Beyond this, additional strategies include:

- Direction and oversight at the Board level to ensure climate risks are factored into strategic business decisions and that we adhere to high environmental standards,
- Continued investment in technologies that improve GHG performance. These include cogeneration and enhanced recovery methods such as eMSAGP and eMVAPEX,
- Supporting a framework for corporate disclosure on climate-related initiatives, including participation in the Carbon Disclosure Project (CDP) global disclosure system for investors, companies, cities, states and regions to manage their environmental impacts,
- Active engagement on GHG policy development, including participation at the Oil Sands Advisory Group to provide guidance under Alberta's Climate Leadership Plan,
- Establishing a set of actions which we expect will enable the company to reach a goal of improving corporate GHG performance to further our commitment to intensity reductions. This target is a component of MEG's company-level compensation package, and
- Maintaining cross-functional teams to review GHG operational performance and identify areas for efficiency improvements.

MEG has established a set of actions which we anticipate will improve the company's GHG performance and further our commitment to

GHG

intensity reductions

Driven By Technology

NEW RESERVOIR PROCESSES AND CONTINUOUS OPTIMIZATIONS REDUCE MEG'S ENVIRONMENTAL IMPACT

MEG uses steam-assisted gravity drainage, or SAGD, technology to recover bitumen from the oil sands. SAGD technology uses horizontal wells to access the resource deep underground, where steam is injected to warm and soften the bitumen so it can be pumped to the surface. This recovery method differs from mining extraction and does not necessitate tailings ponds or the use of surface water in the process.

STEAM-OIL RATIO (SOR)

MEG places significant focus on optimizing steam generation to improve environmental outcomes. An important metric for this purpose is Steam-Oil Ratio (SOR), the quantity of steam used to produce a barrel of oil. SOR is a key measure of efficiency for SAGD projects, with a lower SOR indicating that the steam is more efficiently utilized. By decreasing the amount of steam used, MEG is able to reduce our per barrel water and fuel requirements which results in lower greenhouse gas emissions intensity and more economic projects.

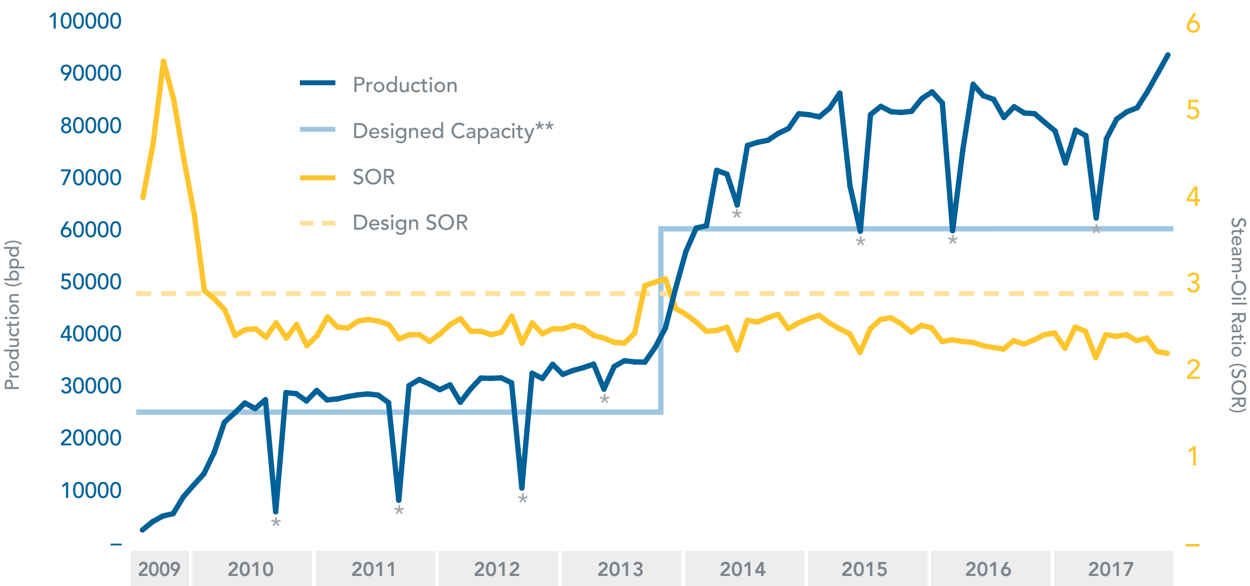
When about one-third of the resource from a well pattern has been recovered using SAGD and the reservoir has been heated and pressurized, MEG's patented, proprietary eMSAGP technology can be introduced. eMSAGP involves injecting a non-condensable gas, like natural gas, into the reservoir to replace a significant portion of the steam.

With the SAGD industry average SOR running about 3 to 3.5, eMSAGP has enabled MEG to achieve a company-wide SOR of just 2.3 for 2017 with corresponding reductions in emissions intensity and water use. At the specific well patterns where eMSAGP has already been implemented, MEG's SOR has been reduced to as low as the 1.2 range.

MEG is currently piloting eMVAPEX, a continuation of eMSAGP, which involves the injection of a solvent into the reservoir with the aim to further reduce the company's SOR far beyond the decreases associated with the eMSAGP process. MEG is encouraged by test results on the eMVAPEX pilot project as we expand it to more wells in 2018.

We believe our investment in technology and willingness to explore new recovery methods will help to further reduce the company's environmental footprint into the future.

MONTHLY PRODUCTION AND STEAM-OIL RATIO



Planned Plant Turnaround

** *The designed capacities shown in this table do not reflect the anticipated production increases expected to result from the implementation of MEG's new reservoir processes and optimizations.*


eMSAGP and cogeneration have enabled MEG to lower its GHG intensity
22% below
the industry average

Emissions

MEG PRODUCES ONE OF THE LOWEST GHG INTENSITY BARRELS IN THE OIL SANDS INDUSTRY

COGENERATION

Cogeneration, the process of recovering waste heat from electricity generation to efficiently produce steam, is another key technology implemented at MEG. We use the steam generated from cogeneration for SAGD bitumen recovery and the electricity to power the plant site, with excess power sold to Alberta's power grid. The electricity provided to the power grid has a lower carbon footprint than the provincial average, helping to reduce total GHG intensity for provincial consumers. The use of cogeneration reduces the net greenhouse gas intensity of our oil and provides a stable source of baseload power as coal-fired generation is phased out in Alberta.

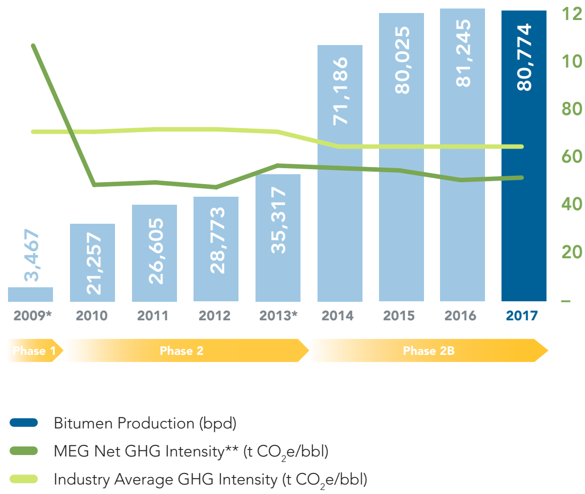
GREENHOUSE GASES

MEG continuously monitors facility GHG performance, facility efficiency and regulatory requirements. Because eMSAGP uses less steam on a per barrel basis, it enables the company to increase production while reducing water and energy use per barrel, with a corresponding reduction in our GHG intensity. Our overall net GHG emissions intensity is currently 22% below the industry average, and has the potential to be reduced even further as we expand eMSAGP and continue developing eMVAPEX.

METHANE

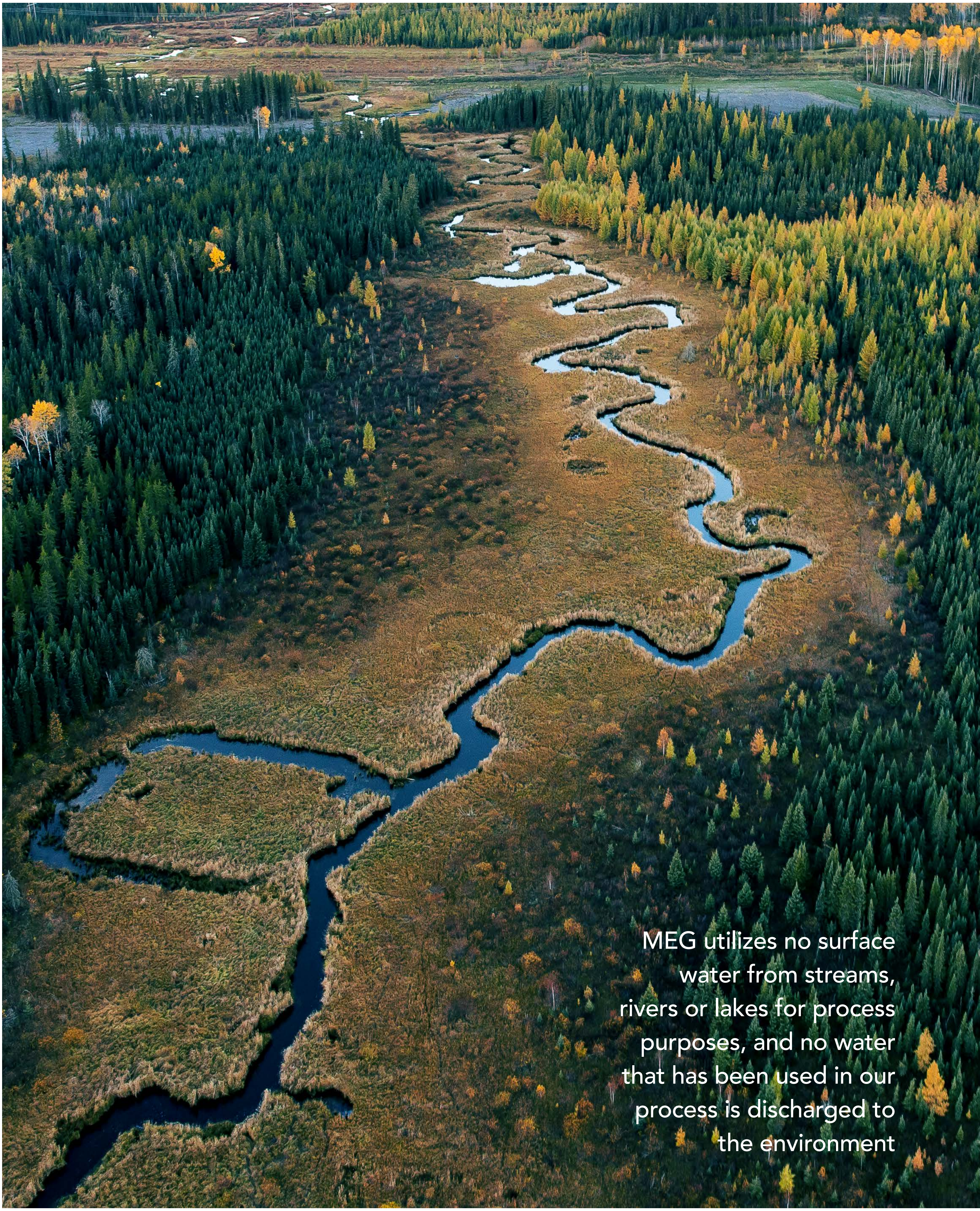
Reducing methane emissions is an important aspect of addressing climate change. MEG has implemented a fugitive emissions management plan for managing fugitive emissions from equipment leaks, a primary source of methane emissions. The plan utilizes a number of inspection techniques including comprehensive leak surveys, permanent instrument monitoring, and targeted monthly and quarterly monitoring. Leaks are documented, tracked and repaired. In addition, our Christina Lake facility is a gas conserving facility, which means overall venting and flaring is virtually eliminated in normal operating conditions. We only flare when it is absolutely necessary to maintain safe plant operations.

NET GHG INTENSITY PERFORMANCE



Sources: MEG's net GHG data from 2010-2016 has been third-party verified. 2017 data is preliminary. In situ industry average estimate is calculated based on the most recent reported data to Environment Canada, Alberta Energy Regulator, and Alberta Electric System Operator.

** Phase start-up: higher steam requirements with low initial production*
*** Net GHG intensity includes the associated benefits of cogeneration*


MEG utilizes no surface water from streams, rivers or lakes for process purposes, and no water that has been used in our process is discharged to the environment

Water

eMSAGP REDUCES MEG'S PER BARREL STEAM REQUIREMENT RESULTING IN LESS WATER USED IN OUR OPERATIONS

Between 2011 and 2017, our eMSAGP process and optimization of recycling technology enabled the company to reduce our total make-up water use intensity by 52%. MEG also recycled 90% of the water we utilized to produce steam in 2017. As a result, the ratio of make-up water we use compared to the bitumen we develop is about 40% lower than the in situ industry average according to the published Alberta Energy Regulator *Alberta Energy Industry Water Use Report*.

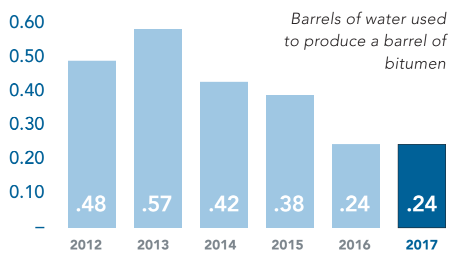
The water needed to produce steam for MEG's SAGD operations comes from two sources. The first is non-drinkable sources located deep under the ground. These sources include saline and non-saline aquifers, unsuitable for human or agricultural use, located hundreds of metres below surface from the hydrocarbon-bearing Clearwater and McMurray formations. Because of their depths, withdrawal of water from these aquifers has minimal environmental impact.

The second source is produced water, which is composed mainly of injected steam that is produced back along with the bitumen. Approximately 90% of the water utilized is recycled on an ongoing basis.

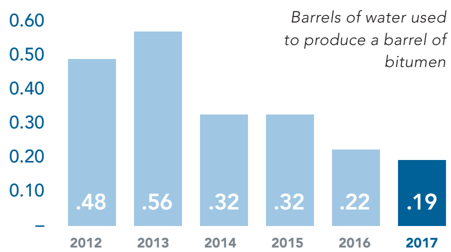
In 2016 and 2017 MEG completed a number of optimization projects to reduce our non-saline water use intensity by 61% from 2011. Prior to 2016, a portion of the make-up water consumed within MEG's Christina Lake facility was used to cool produced water. Optimization work throughout 2016 allowed us to stop using this "quench" water flow, significantly reducing our overall facility non-saline and make-up water intensities.

In late 2016 and early 2017, MEG implemented optimization changes to our saline water system. We replaced non-saline water with saline water as the primary make-up water source for steam generation, enabling MEG to further reduce our non-saline water use intensity factor beyond the levels we achieved in 2016. Non-saline water accounts for just 8% of all the water used for our operations.

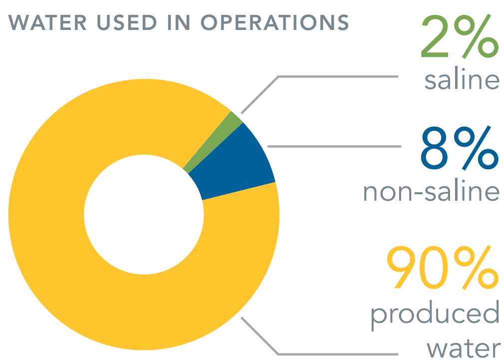
TOTAL WATER WITHDRAWAL INTENSITY

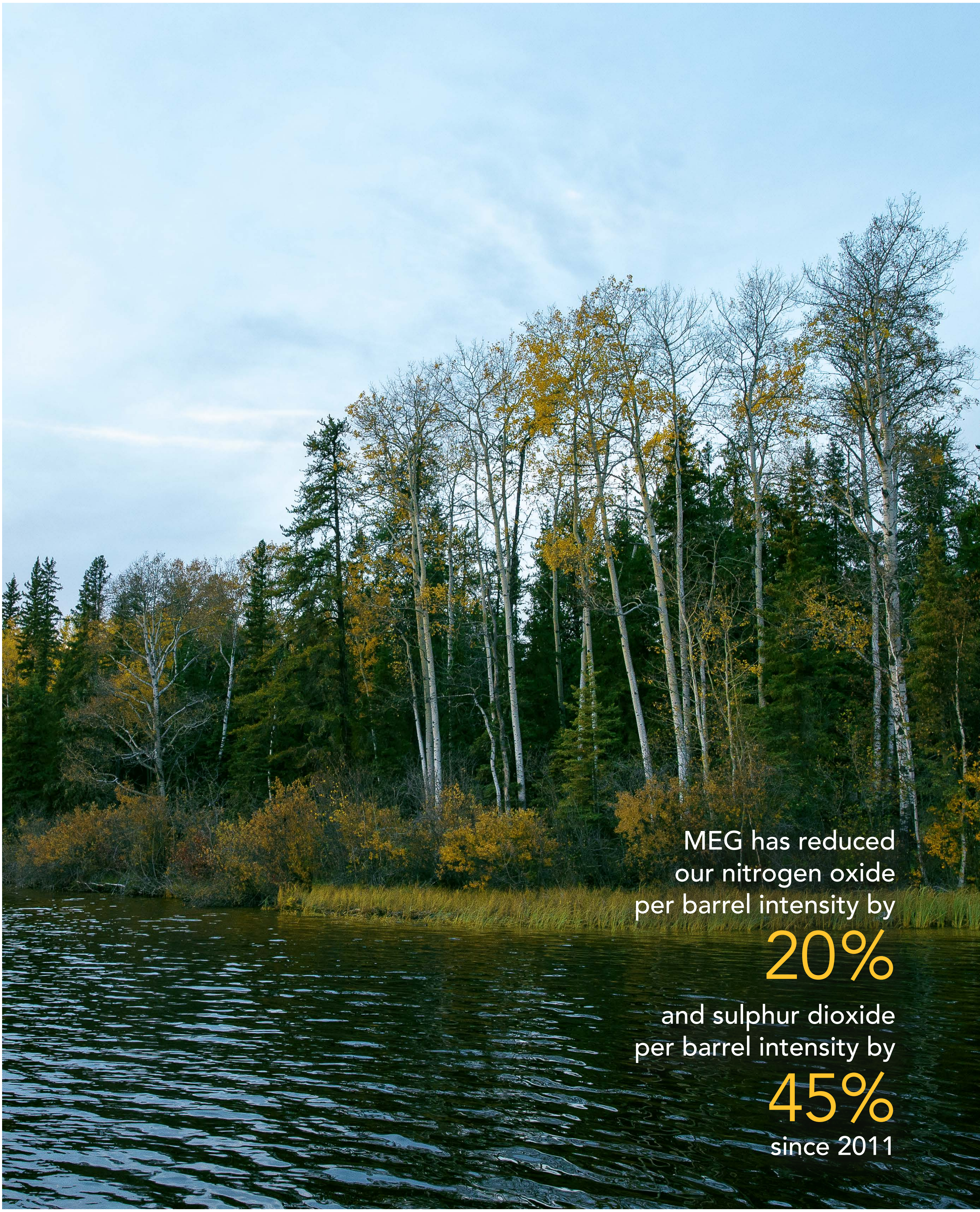


NON-SALINE WATER USE INTENSITY



WATER USED IN OPERATIONS




MEG has reduced our nitrogen oxide per barrel intensity by
20%
and sulphur dioxide per barrel intensity by
45%
since 2011

Improving Air Quality and Preventing Spills

MEG'S PROACTIVE APPROACH MITIGATES IMPACTS AND HELPS CREATE POSITIVE OUTCOMES

AIR QUALITY

Nitrogen oxide (NO_X) and sulphur dioxide (SO_2) are byproducts of the fuel combustion process for steam generation. MEG has addressed these air emissions by investing in low NO_X burners and combustion control technologies to lower NO_X emissions. In 2017, MEG installed a second sulphur recovery unit for sulphur removal, further reducing SO_2 intensity. The reduction in air emission intensities is also a result of continued eMSAGP deployment and associated reduction in SOR. We have reduced our nitrogen oxide and sulphur dioxide per barrel intensities by 20% and 45% respectively since 2011. In accordance with regulatory requirements, MEG recovers 70% of the SO_2 produced at our facility.

SPILL PREVENTION

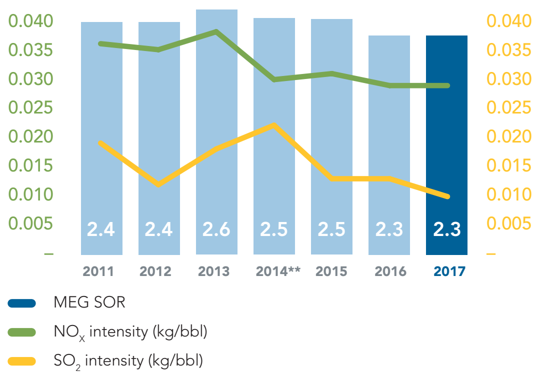
MEG tracks spills[1], including hydrocarbons and non-hydrocarbons, across our operations. The prevention of spills or reduction in their severity is a key environmental initiative at MEG. We identify trends so we can understand causes of spills and implement appropriate preventative measures. Spill awareness campaigns are used to communicate spill performance and improve spill prevention including the reduction in the number and volume of spills.

We actively work to limit the size and frequency of spills. The Access Pipeline has only leaked a single litre of oil since it began operating in 2007. At Christina Lake, we had just six spills in 2017, averaging 5.83 cubic metres. Each was contained on site and cleaned up. No water bodies were impacted.

Spill prevention, response and reporting training is provided to MEG personnel. When a spill is identified, MEG responds promptly using appropriate containment and clean up measures. In 2017, we added a spill performance target to the company's corporate performance targets for 2018 and onwards. We continue to work toward our goal of zero spills.

(1) *The Alberta Energy Regulator defines a reportable spill as a release where oil, water, or unrefined product is spilled and is not confined to the site of the well or facility from which the spill or release occurred; is on site and is in excess of two cubic metres; or that may cause, is causing, or has caused an adverse effect according to Alberta's Environmental Protection and Enhancement Act.*

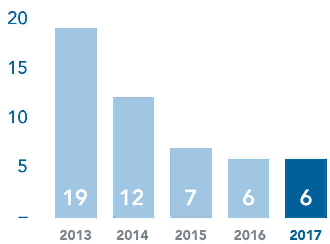
NO_X AND SO_2 INTENSITY*



** MEG's NO_X / SO_2 intensity data from 2011-2016 has been third-party verified. 2017 data is preliminary.*

*** Sulphur removal facility installed at central plant.*

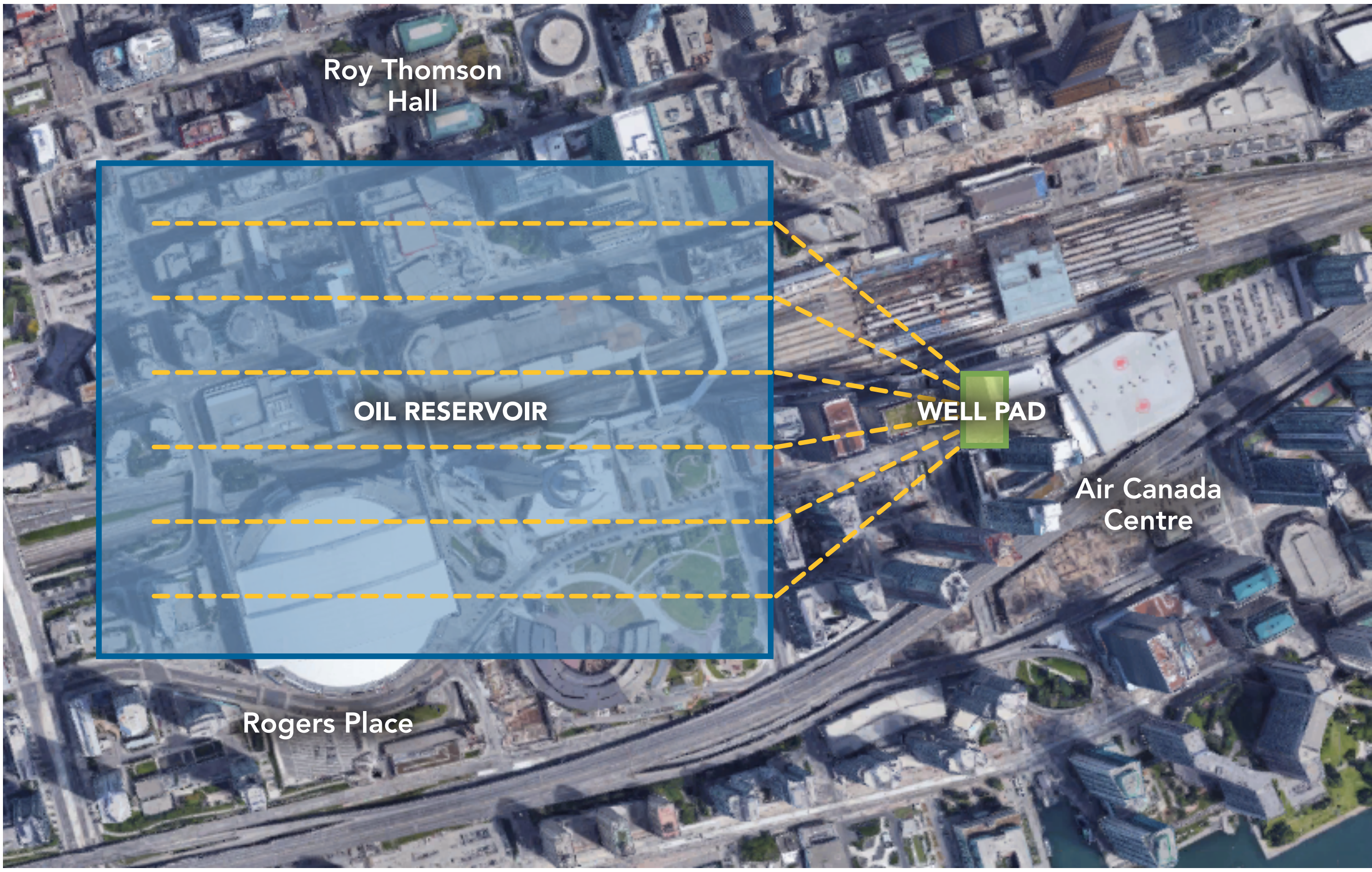
SPILL COUNT



A Smaller Footprint

MEG UTILIZES A MUCH SMALLER SURFACE AREA RELATIVE TO OTHER PROCESSES

The multi-well pad layout associated with SAGD technology, combined with horizontal drilling, enables MEG to limit the size of our production facilities to just 10% to 15% of the land surface of a lease. SAGD technology allows six to 12 well pairs to produce from one well pad, which reduces our surface impact and increases operational efficiency. Because MEG's oil extraction occurs deep below the surface, natural ecosystems, including wetlands, trees and lakes are protected.



Map of downtown Toronto, Ontario

Well pad equivalent to size of **2 CFL fields** (above ground)

Accessing oil reservoir equivalent to size of **62 CFL fields** (below ground)

Containing **12 - 15 million** barrels of oil

MEG is implementing a new well pad design that is reducing their surface footprint by as much as 40%, which also decreases construction timelines and costs. The Gen-C design will be implemented on three well pads which come on stream in 2018 and all future well pads at Christina Lake. The company has also reduced GHG emissions at the Gen-C pads by replacing natural gas heaters with heaters powered by electricity, and will continue to utilize the MEG standard practice of powering our drilling rigs with electricity, produced by cogeneration at the central plant and routed to the site, as opposed to diesel.

In addition, MEG is now having all new well pad surface infrastructure manufactured at fabrication shops in a modular format and having it shipped to site for final bolt-up, as opposed to fabricating components at the site. This has reduced the amount of onsite man-hours needed to build a well pad by more than 70% from 100,000 to just 25,000 and cut our cost to build each new well pair by nearly half. It also reduces the human footprint of our workers at site and in camp, as well as the cost and emissions from transportation of workers to and from our Christina Lake site.

In addition, MEG is optimizing the design of our access roadways and gathering lines to reduce right of way widths and our overall footprint. We are reducing the amount of bed material by up to 40% under many of our new site roads to cut the amount of clay we have to remove from Christina Lake borrow pits, decreasing their size and lowering the cost of hauling materials and building roads by nearly 50%.

MEG is utilizing an innovative method for building roads through wet conditions at Christina Lake that reduces their environmental impact and is much less expensive than traditional practices.

The company has implemented a solution that would increase road-bearing strength without significant excavations and ground disturbance. We use multiple levels of a sourced-in-Alberta "geoweb" material that is stretched like a blanket over the ground, filled with locally-sourced heavy sand to create a sub-base, and covered with a normal gravel finishing surface. When heavy vehicles drive over the surface, the layers disperse the downward pressure from the traffic horizontally. This technology is enabling MEG to build industrial-strength roads over wet conditions with much less hydrologic disturbance than traditional construction methods. This practice will also significantly improve the effectiveness of future road reclamation.

MEG's Pad L utilizes the new Gen-C well pad design which has reduced its overall size by

up to 40%

from previous designs

New technology

enables MEG to build access roads at Christina Lake through wet conditions

Reclaiming the Land

WE AVOID AREAS OF SIGNIFICANCE WHEN PRACTICABLE AND TAKE MEASURES TO MITIGATE IMPACTS WHERE NECESSARY

MEG builds on land previously used for access roads or exploration to minimize overall land disturbance when we can, and we share common corridors and roads with our industrial neighbours and local land users.

We use progressive reclamation plans to minimize the footprint of disturbance and return the land to a state of equivalent capability. All topsoil, subsoil and peat materials are carefully salvaged and preserved to re-establish native plants once the land is ready to be reclaimed. Progressive reclamation is currently used for MEG's exploration areas and will continue with well pads and roads when they are no longer productive or needed.

RECLAMATION PLANS

In 2017, MEG conducted a number of important reclamation activities, including continuing reclamation of four borrow pits used to provide clay for building roads to well pads. The work includes re-contouring relief to natural landforms, replacing the topsoil, and replanting trees, bushes and grasses. MEG also has an active reclamation program for its oil sands evaluation (OSE) wells. To date, MEG has received reclamation certificates on 15 OSE programs and an additional 18 OSE programs have reclamation certificate applications pending or are undergoing reclamation.

MEG's participation in industry working groups including the Faster Forests program by Canada's Oil Sands Innovation Alliance (COSIA), the Industrial Footprint Reduction Options Group and the Regional Industry Caribou Collaboration continues to encourage innovation and application of industry-leading oil sands construction, reclamation and restoration best management practices.

MANAGING DRILLING WASTE

MEG is continually improving our drilling practices and technology to reduce solid waste generated while drilling SAGD wells at Christina Lake. Since 2014, we have reduced solid waste, which includes drill cuttings and cement returns, from drilling. This reduction also cuts down on the truck transport needed to remove solid waste from site and a corresponding reduction in emissions associated with disposal. MEG is also exploring technology that would separate hydrocarbons from impacted drill cuttings, which would increase our onsite disposal options and ultimately enable MEG to process drill cuttings into an inert material usable for reclamation at our Christina Lake site.

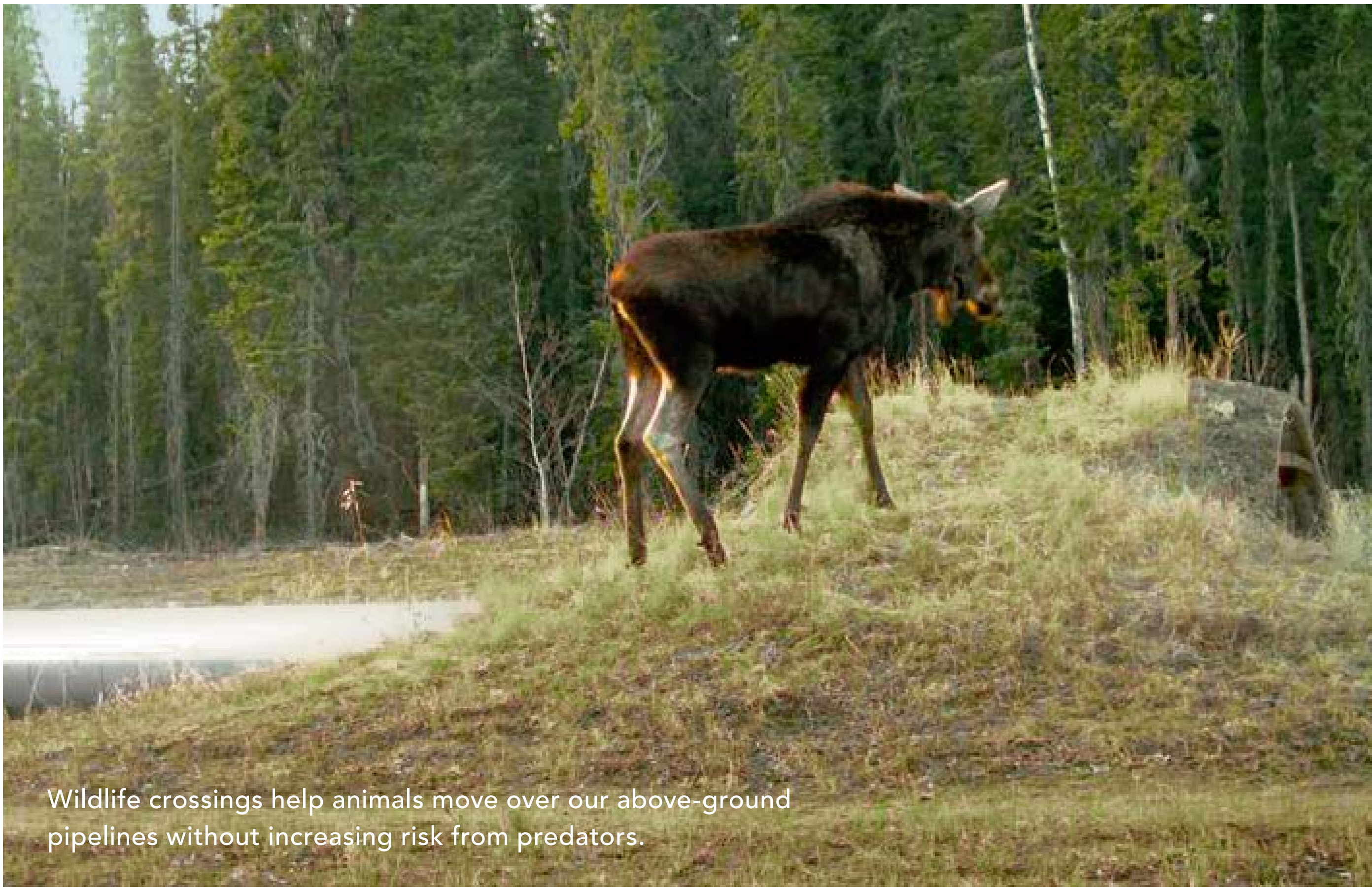
Industrial use corridor
before
restoration

after
restoration has commenced

Minimizing Impact on Wildlife

MEG'S COMPLETE WILDLIFE MONITORING AND MITIGATION PLAN AND CARIBOU PLAN HELP MINIMIZE ANY IMPACTS ON MAMMALS, BIRDS AND FISH

We limit new land disturbance and allow for wildlife movement in and around our project area. Wildlife crossings are strategically placed over our above-ground pipelines to help wildlife move as freely as possible without increasing risk from predators. These crossing locations are carefully selected using data collected on wildlife activity in the area.



Wildlife crossings help animals move over our above-ground pipelines without increasing risk from predators.




We also keep seismic lines narrow and limit straight clearing distances that can expose wildlife populations to predators and recreational hunters. When no longer required, MEG uses habitat restoration techniques to further reduce linear sightlines and restores caribou habitat through treatments such as reforestation to promote the growth of naturally occurring vegetation.

MEG's approach to managing wildlife at the Christina Lake Regional Project has been certified by the Wildlife Habitat Council (WHC). MEG's WHC certification represents independent, third-party validation of our commitment to managing quality habitat for wildlife, conservation education and community outreach initiatives.

PROTECTING CARIBOU POPULATIONS AT CHRISTINA LAKE

Living in the boreal forest across North America, the Woodland Caribou have a less expansive home range than other land mammals and are sensitive to habitat disruptions such as human disturbance and wildfires. The indirect effect from these disturbances is an increased predation rate by wolves, drawn by the presence of prey species such as moose and deer that forage in disturbed areas. These population declines have resulted in the Woodland Caribou being listed as threatened under the federal Species at Risk Act and provincial Wildlife Act.

A key focus for MEG has been caribou habitat restoration to aid in species preservation. We have actively supported the process to develop provincial range plans that will outline protective measures for caribou and have implemented a monitoring and mitigation program that has been designed to effectively contribute to maintaining wildlife populations and habitat in and around our lease. These approaches minimize the impact of development on wildlife movement, ecology and behavior and incorporate site-specific considerations to limit habitat alteration so areas can be restored to the surrounding environment.

This work has not only been undertaken within the areas disturbed by oil sands development but on surrounding legacy disturbances from historical oil and gas activities. The benefit of treating surrounding areas not owned by MEG is to support expanded areas of intact habitat to enable caribou recovery.

In addition, MEG has adopted operational practices to reduce our footprint, improve caribou habitat connectivity impeded by surface infrastructure, and restrict movement along corridors to lessen predator effectiveness, a primary threat to caribou survival. We have also supported partnerships with industry and government on caribou research and habitat restoration.

Over the past two years, MEG has completed off-lease restoration of quality caribou habitat to the east of our Christina Lake operations. This has been a unique opportunity to test a variety of restoration practices to provide a measurable net benefit on the landscape. We have established progressive targets and plan to continue restoration activities in the surrounding areas into the future.

The information collected from caribou collar data winter tracking records and wildlife cameras suggest that caribou can continue to use the landscape alongside properly-managed industrial development.

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the year ended December 31, 2017 was approved by the Board of Directors on March 8, 2018.

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, 2017 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.

2017
ANNUAL REPORT

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 owns a 100% working interest in over 900 square miles of oil sands leases. For information regarding MEG's estimated reserves contained in the GLJ Petroleum Consultants Ltd. Report ("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 barrels per day ("bbls/d") of bitumen production. MEG has applied for regulatory approval for 120,000 bbls/d of bitumen production at the Surmont Project. 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.

The Corporation's first two production phases at the Christina Lake Project, Phase 1 and Phase 2, commenced production in 2008 and 2009, respectively. In 2012, the Corporation announced the RISER initiative, which is a combination of proprietary reservoir technologies, including enhanced Modified Steam And Gas Push ("eMSAGP") and redeployment of steam and facilities modifications, including debottlenecking and brownfield expansions (collectively "RISER"). Phase 2B commenced production in 2013. Bitumen production at the Christina Lake Project for the year ended December 31, 2017 averaged 80,774 bbls/d. The application of eMSAGP and cogeneration have enabled MEG to lower its greenhouse gas intensity below the in situ industry average calculated based on reported data to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. In those specific well patterns where the implementation of eMSAGP has already been deployed, the Corporation is currently experiencing a steam-oil ratio of approximately 1.3. MEG is currently continuing the process of implementing the RISER initiative, and specifically eMSAGP, to Phase 2B of the Christina Lake Project.

The Surmont Project has an anticipated design capacity of approximately 120,000 bbls/d over multiple phases. The Surmont Project is located approximately 30 miles north of the Corporation's Christina Lake Project, and is situated along the same geological trend as the Christina Lake Project. The Corporation is actively pursuing regulatory approval.

MEG currently holds a 100% interest in the Stonefell Terminal, located near Edmonton, Alberta, with a storage and terminalling capacity of 900,000 barrels. The Stonefell Terminal provides the Corporation with the ability to sell and deliver Access Western Blend ("AWB" or "blend") opportunistically to a variety of markets, access multiple sources of diluent, and store both blend and diluent, including in periods of market and transportation disruptions or constraints. The Stonefell Terminal is directly connected by pipeline to a third party rail-loading terminal near Bruderheim, Alberta. This combination of facilities allows for the loading of bitumen blend for transport by rail.

MEG currently holds a 50% interest in the Access Pipeline, a dual pipeline system that connects the Christina Lake Project to a large regional upgrading, refining, diluent supply and transportation hub in the Edmonton, Alberta area.

The Corporation is taking a number of steps to address its financial leverage. In January 2017, MEG successfully completed a refinancing which pushed the first maturity of any of the Corporation's outstanding long-term debt obligations to 2023. The ongoing implementation of the eMSAGP growth project will increase future production while further reducing MEG's per barrel costs, and strengthen the Corporation's ability to deal with the current volatility in crude oil prices.

On February 8, 2018 the Corporation announced that it had entered into an agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of MEG's senior secured term loan and to fund MEG's 13,000 bbls/d Phase 2B brownfield expansion. Closing of the transaction is anticipated to occur in the first quarter of 2018. As part of the transaction, MEG entered into a Transportation Services Agreement ("TSA") dedicating MEG's Christina Lake production and condensate transport to Access Pipeline for an initial term of 30 years. The 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.

In addition, the Corporation continues to consider, taking into account MEG's debt maturity profile and the ongoing price environment, other available options to reduce its overall amount of debt over time.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

During 2017, the Corporation continued to benefit from increases in its realized sales price. The average US$ WTI price increased 18% in 2017 compared to 2016. Also, the average WCS differential narrowed by US$1.86 per barrel, or 13%, due to higher demand for Canadian heavy oil from U.S. Gulf Coast refineries. These factors were the primary drivers in the approximately C$14 per barrel increase in bitumen realization in 2017, as compared to 2016.

Capital investment in 2017 totaled $502.8 million, an increase of $365.5 million compared to the same period of 2016, primarily as a result of increased investment in the eMSAGP growth project at Christina Lake Phase 2B. Total capital investment for 2017 approximated the Corporation's most recent guidance of $510 million.

At December 31, 2017, the Corporation had cash and cash equivalents of $463.5 million and US$1.4 billion of undrawn capacity under the revolving credit facility.

The Corporation continues to benefit from efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake project. Still in the first year of a two-year development plan, the eMSAGP growth project is proceeding as planned. The implementation of eMSAGP has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production. Exit bitumen production volumes for 2017 were 93,674 bbls/d.

The Corporation's non-energy operating costs averaged $4.62 per barrel for 2017, an 18% decrease compared to $5.62 per barrel in 2016. The decrease in costs is a result of efficiency gains and continued cost management.

The Corporation realized net earnings of $166.0 million for the year ended December 31, 2017. Net earnings are impacted by the foreign exchange rate as the Corporation's debt is denominated in U.S. dollars. The Canadian dollar strengthened overall in 2017, resulting in an unrealized foreign exchange gain of $338.1 million on a year-to-date basis.

On December 1, 2017, the Corporation announced a 2018 capital budget of $510 million. On February 8, 2018, following the announcement of the agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal, the Corporation announced that it intends to increase its 2018 capital budget from $510 million to $700 million to fund approximately 70% of the Phase 2B brownfield expansion in 2018. The Corporation expects to fund the 2018 capital program with internally generated cash flow, a portion of its $463.5 million of cash and cash equivalents as at December 31, 2017 and a portion of the proceeds from the asset sales.

The Corporation's 2018 annual bitumen production volumes are targeted to be in the range of 85,000 – 88,000 bbls/d. Exit bitumen production for 2018 is targeted to be in the range of 95,000 – 100,000 bbls/day. Non-energy operating costs are targeted to be in the range of $4.75 – $5.25 per barrel. The operational guidance takes into account a major turnaround at the Corporation's Christina Lake Phase 2B facility in 2018, with an anticipated 5,000 to 6,000 bbls/d impact on production for the year.

The following table summarizes selected operational and financial information of the Corporation for the years noted. All dollar amounts are stated in Canadian dollars ($ or C$) unless otherwise noted:

($ millions, except as indicated)	2017	2016
Bitumen production - bbls/d	**80,774**	81,245
Bitumen realization - $/bbl	**41.89**	27.79
Net operating costs - $/bbl(1)	**6.84**	7.99
Non-energy operating costs - $/bbl	**4.62**	5.62
Cash operating netback - $/bbl(2)	**27.00**	13.13
Adjusted funds flow from (used in) operations(3)	**374**	(62)
Per share, diluted(3)	**1.29**	(0.27)
Operating earnings (loss)(3)	**(114)**	(455)
Per share, diluted(3)	**(0.39)**	(2.01)
Revenue(4)	**2,435**	1,866
Net earnings (loss)	**166**	(429)
Per share, basic	**0.57**	(1.90)
Per share, diluted	**0.57**	(1.90)
Total cash capital investment	**503**	137
Cash and cash equivalents	**464**	156
Long-term debt	**4,668**	5,053

(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, 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 from (used in) operations, 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 from (used in) operations 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 under the heading "NON-GAAP MEASURES" and discussed further 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.*

RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	2017	2016
Bitumen production – bbls/d	**80,774**	81,245
Steam-oil ratio (SOR)	**2.3**	2.3

Bitumen Production

Bitumen production for the year ended December 31, 2017 averaged 80,774 bbls/d compared to 81,245 bbl/d for the year ended December 31, 2016. Average production for 2017 was affected by a planned 37-day turnaround at the Christina Lake Project, which was successfully completed in early June. The 2017 turnaround had a greater impact on production volumes compared to only minor capital activities during the same period in 2016.

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 maintaining efficiency of production through a lower SOR. The SOR averaged 2.3 for the years ended December 31, 2017 and 2016.

Operating Cash Flow

($000)	2017	2016
Petroleum revenue – proprietary[(1)]	**$ 2,168,602**	$ 1,626,025
Diluent expense	**(944,134)**	(808,030)
	1,224,468	817,995
Royalties	**(22,578)**	(8,581)
Transportation expense	**(214,280)**	(209,864)
Operating expenses	**(222,196)**	(253,758)
Power revenue	**22,209**	18,868
Transportation revenue	**12,801**	19,791
	800,424	384,451
Realized gain (loss) on commodity risk management	**(11,273)**	2,359
Operating cash flow[(2)]	**$ 789,151**	$ 386,810

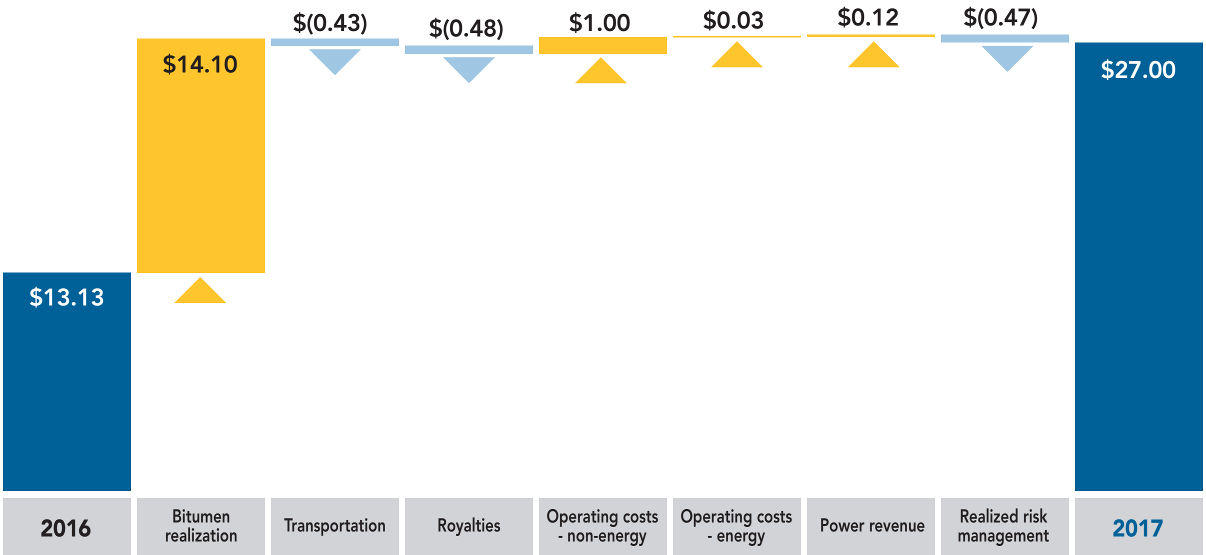
(1) Proprietary petroleum revenue represents MEG's revenue ("blend sales revenue") from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.

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

Operating cash flow was $789.2 million for the year ended December 31, 2017 compared to $386.8 million for the year ended December 31, 2016. The 104% increase is primarily due to higher blend sales revenue as a result of the increase in average crude oil benchmark pricing, partially offset by an increase in diluent expense. The increase in blend sales revenue is primarily due to a 35% increase in the average realized blend price. Diluent expense for the year ended December 31, 2017 was $136.1 million higher than the year ended December 31, 2016, primarily due to an increase in condensate prices.

Cash Operating Netback

$/bbl



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

($/bbl)	2017	2016
Bitumen realization(1)	**$ 41.89**	$ 27.79
Transportation(2)	**(6.89)**	(6.46)
Royalties	**(0.77)**	(0.29)
	34.23	21.04
Operating costs – non-energy	**(4.62)**	(5.62)
Operating costs – energy	**(2.98)**	(3.01)
Power revenue	**0.76**	0.64
Net operating costs	**(6.84)**	(7.99)
	27.39	13.05
Realized gain (loss) on commodity risk management	**(0.39)**	0.08
Cash operating netback	**$ 27.00**	$ 13.13

(1) Blend sales revenue net of diluent expense.

(2) Defined as transportation expense less transportation revenue. Transportation includes rail, third-party pipelines and the Stonefell Terminal costs, as well as MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries on diluent transportation arrangements.

Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary petroleum revenue ("blend sales revenue"), net of 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. 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 $41.89 per barrel for the year ended December 31, 2017 compared to $27.79 per barrel for the year ended December 31, 2016. The increase in bitumen realization is primarily a result of the increase in average crude oil benchmark pricing, which resulted in higher blend sales revenue.

For the year ended December 31, 2017, the Corporation's cost of diluent was $72.32 per barrel of diluent compared to $61.06 per barrel of diluent for the year ended December 31, 2016. The increase in the cost of diluent is primarily a result of the increase in average condensate benchmark pricing.

Transportation

The Corporation utilizes multiple facilities to transport and sell its blend to refiners throughout North America. In early 2016, the Corporation increased its transportation capacity on the Flanagan South and Seaway pipeline systems, thereby furthering the Corporation's strategy of broadening market access to world prices with the intention of improving cash operating netback. Sales volumes destined for U.S. markets require additional transportation costs, but generally obtain higher sales prices. As a result of a higher proportion of blend sales volumes shipped from Edmonton to the U.S. Gulf Coast via the Flanagan South and Seaway pipeline systems during the year ended December 31, 2017, transportation costs averaged $6.89 per barrel for the year ended December 31, 2017 compared to $6.46 per barrel for the year ended December 31, 2016.

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.

The increase in royalties for the year ended December 31, 2017, compared to the year ended December 31, 2016 is primarily the result of higher realized 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 represent production-related operating activities. Energy operating costs represent 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, 2017 averaged $6.84 per barrel compared to $7.99 per barrel for the year ended December 31, 2016. The decrease in net operating costs is primarily the result of a per barrel decrease in non-energy operating costs.

Non-energy operating costs

Non-energy operating costs averaged $4.62 per barrel for the year ended December 31, 2017 compared to $5.62 per barrel for the year ended December 31, 2016. The decrease in non-energy operating costs is primarily the result of efficiency gains and a continued focus on cost management resulting in lower operations staffing and materials and services costs, plus a $0.15 per barrel, or $4.5 million reduction of property taxes related to a one-time municipal reassessment of its Christina Lake facility in the second quarter of 2017.

Energy operating costs

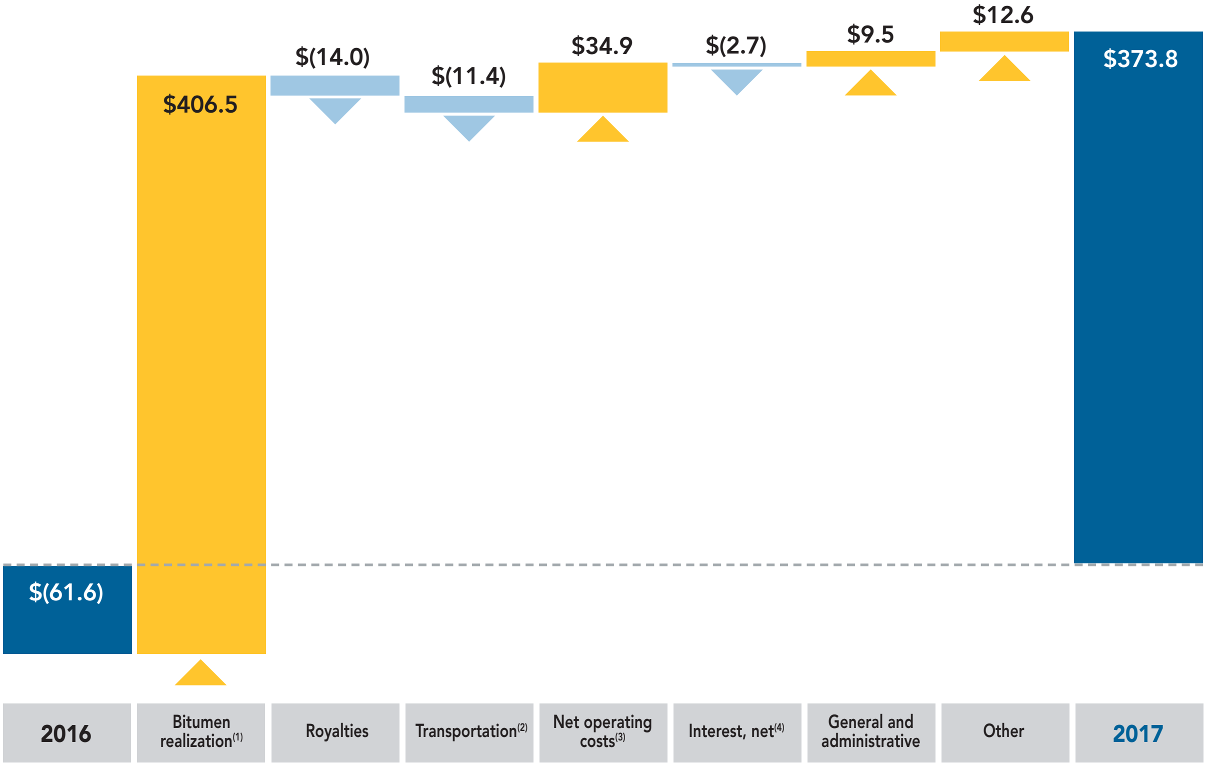
Energy operating costs averaged $2.98 per barrel for the year ended December 31, 2017 which were substantially consistent with $3.01 per barrel for the year ended December, 2016. The Corporation's natural gas purchase price averaged $2.59 per mcf during the year ended December 31, 2017 compared to $2.53 per mcf for the same period in 2016.

Power revenue

Power revenue averaged $0.76 per barrel for the year ended December 31, 2017 compared to $0.64 per barrel for the year ended December 31, 2016. The Corporation's average realized power sales price during the year ended December 31, 2017 was $21.49 per megawatt hour compared to $18.74 per megawatt hour for the same period in 2016.

Adjusted Funds Flow From (Used In) Operations – Year Ended December 31

$ millions



(1) *Net of diluent expense.*

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

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

(4) *Defined as total interest expense plus realized gain/loss on interest rate swaps less amortization of debt discount and debt issue costs.*

Adjusted funds flow from (used in) operations 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 from operations was $373.8 million for the year ended December 31, 2017 compared to adjusted funds flow used in operations of $(61.6) million for the year ended December 31, 2016. The increase was primarily due to an increase in bitumen realization, as a result of the increase in average crude oil benchmark pricing.

Operating Earnings (Loss)

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. The Corporation recognized an operating loss of $113.5 million for the year ended December 31, 2017 compared to an operating loss of $455.1 million for the year ended December 31, 2016. The decrease in the operating loss was primarily due to higher bitumen realization as a result of the increase in average crude oil benchmark pricing.

Revenue

Revenue represents the total of petroleum revenue, net of royalties and other revenue. Revenue for the year ended December 31, 2017 totaled $2.43 billion compared to $1.87 billion for the year ended December 31, 2016. Revenue increased primarily due to an increase in blend sales revenue as a result of the increase in average crude oil benchmark pricing.

Net Earnings (Loss)

The Corporation recognized net earnings of $166.0 million for the year ended December 31, 2017 compared to a net loss of $428.7 million for the year ended December 31, 2016. In addition to the impact of higher average crude oil benchmark pricing in 2017 as previously discussed under cash operating netback, the net unrealized foreign exchange gain increased by $190.0 million in 2017 compared to 2016. Also in 2016, the Corporation recognized an $80.1 million impairment charge related to the Northern Gateway pipeline.

Total Cash Capital Investment

Total cash capital investment during the year ended December 31, 2017 totaled $502.8 million as compared to $137.2 million for the year ended December 31, 2016. Capital investment in 2017 has been primarily directed towards the Corporation's eMSAGP production growth initiative at Christina Lake Phase 2B and sustaining capital activities.

OUTLOOK

Summary of 2017 Guidance	Guidance October 26, 2017	Annual Results
Capital investment	$510 million	**$503 million**
Bitumen production – annual average (bbls/d)	80,000 – 82,000	**80,774**
Bitumen production – targeted exit volume (bbls/d)	86,000 – 89,000	**93,674**
Non-energy operating costs ($/bbl)	$4.75 – $5.00	**$4.62**

Capital investment for 2017 was $503 million, which approximated the Corporation's most recent 2017 capital investment guidance of $510 million issued on October 26, 2017.

Annual bitumen production averaged 80,774 bbls/d, consistent with the Corporation's most recent 2017 production guidance.

As a result of the continued implementation of eMSAGP, exit bitumen production volumes were 93,674 bbls/d, which exceeded the Corporation's most recent 2017 exit production guidance.

As a result of efficiency gains and a continued focus on cost management, annual non-energy operating costs averaged $4.62 per barrel, representing a 5% reduction from the mid-point of the most recent 2017 guidance.

Summary of 2018 Guidance	
Capital investment	**$700 million**
Bitumen production – annual average (bbls/d)	**85,000 – 88,000**
Bitumen production – targeted exit volume (bbls/d)	**95,000 – 100,000**
Non-energy operating costs ($/bbl)	**$4.75 – $5.25**

On December 1, 2017, the Corporation announced a 2018 capital budget of $510 million. On February 8, 2018, following the announcement of the agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal, the Corporation announced it intends to increase its 2018 capital budget from $510 million to $700 million to fund approximately 70% of the Phase 2B brownfield expansion in 2018. The Corporation expects to fund the 2018 capital program with internally generated cash flow, a portion of its $463.5 million of cash and cash equivalents as at December 31, 2017 and a portion of the proceeds from the asset sales.

The Corporation's 2018 annual bitumen production volumes are targeted to be in the range of 85,000 – 88,000 bbls/d. Exit bitumen production for 2018 is targeted to be in the range of 95,000 – 100,000 bbls/day. Non-energy operating costs are targeted to be in the range of $4.75 – $5.25 per barrel. The operational guidance takes into account a major turnaround at the Corporation's Christina Lake Phase 2B facility in 2018, with an anticipated 5,000 to 6,000 bbls/d impact on production for the year.

BUSINESS ENVIRONMENT

The following table shows industry commodity pricing information and foreign exchange rates on a quarterly and annual basis to assist in understanding the impact of commodity prices and foreign exchange rates on the Corporation's financial results:

	Year ended December 31		2017				2016			
	2017	**2016**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**54.83**	44.97	**61.54**	52.18	50.93	54.66	51.13	46.98	46.67	35.10
WTI (US$/bbl)	**50.95**	43.33	**55.40**	48.21	48.29	51.91	49.29	44.94	45.59	33.45
WTI (C$/bbl)	**66.13**	57.44	**70.45**	60.38	64.94	68.68	65.75	58.65	58.75	45.99
WCS (C$/bbl)	**50.58**	39.09	**54.86**	47.93	49.98	49.39	46.65	41.03	41.61	26.41
Differential – WTI:WCS (US$/bbl)	**11.98**	13.84	**12.26**	9.94	11.13	14.58	14.32	13.50	13.30	14.24
Differential – WTI:WCS (%)	**23.5%**	31.9%	**22.1%**	20.6%	23.0%	28.1%	29.1%	30.0%	29.2%	42.6%
Condensate prices										
Condensate at Edmonton (C$/bbl)	**66.91**	56.21	**73.72**	59.59	65.16	69.17	64.49	56.25	56.83	47.27
Condensate at Edmonton as % of WTI	**101.2%**	97.9%	**104.6%**	98.7%	100.3%	100.7%	98.1%	95.9%	96.7%	102.8%
Condensate at Mont Belvieu, Texas (US$/bbl)	**48.14**	39.68	**55.35**	46.37	44.77	46.05	45.17	41.17	40.37	32.03
Condensate at Mont Belvieu, Texas as % of WTI	**94.5%**	91.6%	**99.9%**	96.2%	92.7%	88.7%	91.6%	91.6%	88.6%	95.8%
Natural gas prices										
AECO (C$/mcf)	**2.29**	2.25	**1.84**	1.58	2.81	2.91	3.31	2.49	1.37	1.82
Electric power prices										
Alberta power pool (C$/MWh)	**22.17**	18.19	**22.49**	24.55	19.26	22.38	21.97	17.93	14.77	18.09
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.2980**	1.3256	**1.2717**	1.2524	1.3449	1.3230	1.3339	1.3051	1.2886	1.3748
C$ equivalent of 1 US$ - period end	**1.2518**	1.3427	**1.2518**	1.2510	1.2977	1.3322	1.3427	1.3117	1.3009	1.2971

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$50.95 per barrel for the year ended December 31, 2017 compared to US$43.33 per barrel for the year ended December 31, 2016.

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 prices at Hardisty, Alberta. WCS typically trades at a differential below the WTI benchmark price. The WTI:WCS differential averaged US$11.98 per barrel, or 23.5% of WTI, for the year ended December 31, 2017 compared to US$13.84 per barrel, or 31.9% of WTI, for the year ended December 31, 2016.

Condensate Prices

In order to facilitate pipeline transportation, MEG uses condensate sourced throughout North America as diluent for blending with the Corporation's bitumen. Condensate prices, benchmarked at Edmonton, averaged $66.91 per barrel, or 101.2% of WTI, for the year ended December 31, 2017 compared to $56.21 per barrel, or 97.9% of WTI, for the year ended December 31, 2016.

Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$48.14 per barrel, or 94.5% of WTI, for the year ended December 31, 2017 compared to US$39.68 per barrel, or 91.6% of WTI, for the year ended December 31, 2016.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, as it is used as fuel to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facilities. The AECO natural gas price averaged $2.29 per mcf for the year ended December 31, 2017 compared to $2.25 per mcf for the year ended December 31, 2016.

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 $22.17 per megawatt hour for the year ended December 31, 2017 compared to $18.19 per megawatt hour for the year ended December 31, 2016.

Foreign Exchange Rates

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

The Corporation recognizes net unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents at each reporting date. As at December 31, 2017, the Canadian dollar, at a rate of 1.2518, had increased in value by approximately 7% against the U.S. dollar compared to its value as at December 31, 2016, when the rate was 1.3427.

OTHER OPERATING RESULTS

Net Marketing Activity

($000)	2017	2016
Petroleum revenue – third party	**$ 253,486**	$ 205,790
Purchased product and storage	**(250,681)**	(202,135)
Net marketing activity(1)	**$ 2,805**	$ 3,655

(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

($000)	2017	2016
Depletion and depreciation expense	**$ 475,644**	$ 499,811
Depletion and depreciation expense per barrel of production	**$ 16.13**	$ 16.81

Depletion and depreciation expense decreased, 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.

Impairment

There were no impairments recognized in 2017. At December 31, 2016, the Corporation evaluated its investment in the right to participate in the Northern Gateway pipeline for impairment, in relation to the December 6, 2016 directive from the Government of Canada to the National Energy Board ("NEB") to dismiss the project application. As a result, the Corporation fully impaired its investment and recognized a fourth quarter 2016 impairment charge of $80.1 million.

Commodity Risk Management Gain (Loss)

The Corporation has entered into financial commodity risk management contracts. 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.

($000)	2017			2016		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Crude oil contracts[1]	**$ (53,364)**	**$ (9,245)**	**$ (62,609)**	$ (9,888)	$ (59,404)	$ (69,292)
Condensate contracts[2]	**42,091**	**(29,091)**	**13,000**	12,247	29,091	41,338
Commodity risk management gain (loss)	**$ (11,273)**	**$ (38,336)**	**$ (49,609)**	$ 2,359	$ (30,313)	$ (27,954)

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

(2) Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas as a percentage of WTI (US$/bbl).

The Corporation realized a net loss on commodity risk management contracts of $11.3 million for the year ended December 31, 2017, primarily due to net settlement losses on contracts relating to crude oil sales, partially offset by settlement gains on condensate purchase contracts. This compares to a realized net gain of $2.4 million for the year ended December 31, 2016.

The Corporation recognized an unrealized loss on commodity risk management contracts of $38.3 million for the year ended December 31, 2017, reflecting unrealized losses on condensate purchase contracts and crude oil contracts. Crude oil benchmark forward prices increased over the period, resulting in unrealized losses on the Corporation's WTI fixed price contracts and collars. This was partially offset by unrealized gains on WCS fixed differential contracts, due to a widening of WCS forward differentials. The $38.3 million unrealized loss in 2017 compares to a $30.3 million unrealized loss in 2016. Refer to the "Risk Management" section of this MD&A for further details.

General and Administrative

($000)	2017	2016
General and administrative expense	**$ 86,785**	$ 96,241
General and administrative expense per barrel of production	**$ 2.94**	$ 3.24

General and administrative expense decreased primarily due to workforce reductions and the Corporation's continued focus on cost management.

Stock-based Compensation

($000)	2017	2016
Cash-settled expense	**$ 3,476**	$ 16,354
Equity-settled expense	**19,052**	33,588
Stock-based compensation	**$ 22,528**	$ 49,942

The fair value of compensation associated with the granting of stock options, restricted share units ("RSUs"), performance share units ("PSUs") and deferred share units ("DSUs") to officers, directors, employees and consultants is recognized by the Corporation as stock-based compensation expense. Fair values for equity-settled plans are determined using the Black-Scholes option pricing model.

The Corporation also grants RSUs, PSUs and DSUs under cash-settled plans. RSUs generally vest over a three year period while PSUs 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. Upon vesting of the RSUs and PSUs, the participants of the cash-settled RSU plan will receive a cash payment based on the fair value of the underlying share units at the vesting date. The cash-settled RSUs, PSUs and DSUs 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. Fluctuations in the fair value are recognized within stock-based compensation expense or capitalized to property, plant and equipment during the period in which they occur.

Stock-based compensation expense for the year ended December 31, 2017 was $22.5 million compared to $49.9 million for the year ended December 31, 2016. The decrease is primarily due to a decrease in the fair value of cash-settled units due to the decrease in the Corporation's common share price during 2017 in combination with a decrease in equity-settled share-based compensation expense. The Corporation commenced issuing RSUs and PSUs under a cash-settled plan in 2016.

Research and Development

($000)	**2017**	**2016**
Research and development expense	**$ 5,808**	$ 5,499

Research and development expenditures relate to the Corporation's research of crude quality improvement and related technologies.

Foreign Exchange Gain (Loss), Net

($000)	**2017**	**2016**
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ 343,633**	$ 157,272
Other	**(5,489)**	(9,119)
Unrealized net gain (loss) on foreign exchange	**338,144**	148,153
Realized gain (loss) on foreign exchange	**4,403**	3,242
Foreign exchange gain (loss), net	**$ 342,547**	$ 151,395
C$ equivalent of 1 US$		
Beginning of year	**1.3427**	1.3840
End of year	**1.2518**	1.3427

The net foreign exchange gains and losses are primarily due to the translation of the 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 years ended December 31, 2017 and 2016, the Canadian dollar strengthened by 7% and 3%, respectively. This resulted in a net foreign exchange gain of $342.5 million in 2017 compared to a net foreign exchange gain of $151.4 million in 2016.

Net Finance Expense

($000)	2017	2016
Total interest expense	**$ 341,594**	$ 328,335
Total interest income	**(3,924)**	(1,047)
Net interest expense	**337,670**	327,288
Debt extinguishment expense	**30,801**	28,845
Accretion on provisions	**7,760**	7,150
Unrealized loss (gain) on derivative financial liabilities[1]	**(16,179)**	(12,508)
Realized loss on interest rate swaps	**1,028**	4,548
Net finance expense	**$ 361,080**	$ 355,323
Average effective interest rate[2]	**6.1%**	5.8%

(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.

Total interest expense for the year ended December 31, 2017 was $341.6 million compared to $328.3 million for the year ended December 31, 2016. This increase was due to higher effective interest rates and the incremental interest expense associated with carrying both the now repaid US$750 million aggregate principal amount of 6.5% Senior Unsecured Notes and the new 6.5% Senior Secured Second Lien Notes for a period of 49 days during the first quarter of 2017. Given the reduction in the early redemption premium threshold between closing and March 15, 2017, the economic cost of carrying interest on these notes for an incremental 49 days was less than the cost of redeeming the notes prior to March 15, 2017. The 6.5% Senior Unsecured Notes were repaid on March 15, 2017 with the proceeds from the Senior Secured Second Lien Notes. This issuance and repayment of notes was part of the Corporation's comprehensive refinancing plan which is further described in the "LIQUIDITY AND CAPITAL RESOURCES" section of this MD&A.

On February 8, 2018, the Corporation announced that it had entered into an agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal, as described in the "SUBSEQUENT EVENTS" section of this MD&A. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of the Corporation's senior secured term loan. The expected repayment of debt reduces the estimated amortization period of the unamortized debt discount and debt issue costs, and the unamortized financial derivative liability discount. The change in estimate is 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 is 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.

At December 31, 2016, the Corporation recognized $28.8 million of debt extinguishment expense associated with the planned redemption of the 6.5% Senior Unsecured Notes on March 15, 2017, under the comprehensive refinancing plan completed on January 27, 2017, as described in the "LIQUIDITY AND CAPITAL RESOURCES" section of this MD&A.

Unrealized gains and losses on derivative liabilities include changes in fair value of both the interest rate floor associated with the Corporation's senior secured term loan and the interest rate swap contracts. The Corporation recognized an unrealized gain on derivative financial liabilities of $16.2 million for the year ended December 31, 2017 compared to an unrealized gain of $12.5 million for the year ended December 31, 2016.

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%. This interest rate swap contract commenced September 29, 2017 and expires on December 31, 2020. The Corporation realized a loss on the interest rate swaps of $1.0 million for the year ended December 31, 2017. In 2016, the Corporation realized a loss on interest rate swaps of $4.5 million. These swap contracts effectively fixed the interest rate on US$748.0 million of its US$1.2 billion senior secured term loan and expired on September 30, 2016.

Other Expenses

($000)		2017		2016
Contract cancellation expense	**$**	**18,765**	$	-
Onerous contracts		**10,830**		47,866
Severance and other		**5,131**		16,156
Other expenses	**$**	**34,726**	$	64,022

During the third quarter of 2017, the Corporation recognized contract cancellation expense of $18.8 million relating to the termination of a long-term transportation contract.

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

Income Tax Expense (Recovery)

($000)		2017		2016
Current income tax expense (recovery)	**$**	**(67)**	$	919
Deferred income tax expense (recovery)		**(56,130)**		(208,413)
Income tax expense (recovery)	**$**	**(56,197)**	$	(207,494)

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, 2017, the Corporation had approximately $8.4 billion of available Canadian tax pools.

The Corporation recognized a current income tax recovery of $0.1 million and an expense of $0.9 million in the years ended December 31, 2017 and 2016, respectively. 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 the United States income tax associated with its operations in the United States. The 2016 expense was related to the United States income tax associated with its operations in the United States.

The Corporation recognized a deferred income tax recovery of $56.1 million for the year ended December 31, 2017 and a deferred income tax recovery of $208.4 million for the year ended December 31, 2016.

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

- The permanent difference due to the non-taxable portion of realized and unrealized foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the year ended December 31, 2017, the non-taxable net gain was $171.9 million compared to a non-taxable gain of $78.6 million for the year ended December 31, 2016.
- 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, 2017 was $19.1 million compared to $33.6 million for the year ended December 31, 2016.

As at December 31, 2017, the Corporation has recognized a deferred income tax asset of $182.9 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, 2017, the Corporation had not recognized the tax benefit related to $445.7 million of realized and unrealized taxable foreign exchange losses.

NET CAPITAL INVESTMENT

($000)		2017		2016
eMSAGP growth	**$**	**222,982**	$	2,678
Sustaining		**189,288**		64,230
Marketing, corporate and other		**90,484**		70,337
Total cash capital investment		**502,754**		137,245
Capitalized cash-settled stock-based compensation		**(308)**		2,491
	$	**502,446**	$	139,736

Total cash capital investment for the year ended December 31, 2017 was $502.8 million as compared to $137.2 million for the year ended December 31, 2016.

During 2017, the Corporation invested $223.0 million in the first year of its two-year development plan for the eMSAGP growth project at Christina Lake Phase 2B. Also in 2017, the Corporation invested $189.3 million in sustaining capital activities, including turnaround costs of $37.1 million incurred in the second quarter. In 2016, the Corporation was focused on reducing capital spending and capital investments were primarily directed towards sustaining capital activities.

SUMMARY OF QUARTERLY RESULTS

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

	2017				2016			
($ millions, except per share amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue(1)	**$754.8**	**$546.1**	**$574.0**	**$559.8**	$565.8	$496.8	$513.4	$290.3
Net earnings (loss)	**(23.8)**	**83.9**	**104.3**	**1.6**	(304.8)	(108.6)	(146.2)	130.8
Per share – basic	**(0.08)**	**0.29**	**0.36**	**0.01**	(1.34)	(0.48)	(0.65)	0.58
Per share – diluted	**(0.08)**	**0.28**	**0.35**	**0.01**	(1.34)	(0.48)	(0.65)	0.58

(1) *The total of Petroleum revenue, net of royalties and Other revenue as presented on the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss).*

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 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;
- other expenses primarily related to contract cancellation expense, onerous contracts and severance costs;
- a fourth quarter 2016 impairment charge related to the Corporation's investment in the right to participate in the Northern Gateway pipeline; and
- changes in depletion and depreciation expense as a result of changes in production rates and future development costs.

SUMMARY ANNUAL INFORMATION

($000s, except per share amounts)	2017	2016	2015
Revenue[1]	**2,434,703**	1,866,284	1,925,916
Net earnings (loss)	**165,976**	(428,726)	(1,169,671)
Per share – basic	**0.57**	(1.90)	(5.21)
Per share – diluted	**0.57**	(1.90)	(5.21)
Total assets	**9,363,352**	8,921,224	9,400,269
Total non-current liabilities	**4,873,779**	5,271,277	5,474,106

(1) The total of Petroleum revenue, net of royalties and Other revenue as presented on the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss).

Revenue

During 2017, revenue increased 30% from 2016, primarily as a result of the year-over-year average increase in crude oil benchmark pricing.

During 2016, revenue decreased 3% from 2015, primarily as a result of the year-over-year average decline in crude oil benchmark pricing.

Net Earnings (Loss)

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.

The decrease in the net loss in 2016 compared to the net loss in 2015 is primarily attributable to the Corporation recognizing an unrealized foreign exchange gain in 2016 compared to an unrealized foreign exchange loss in 2015. The net loss for the year ended December 31, 2016 was impacted by lower bitumen realization, primarily as a result of the year-over-year average decline in U.S. crude oil benchmark pricing, an impairment charge related to the Northern Gateway pipeline, an unrealized loss on commodity risk management and other expenses primarily related to onerous contracts and severance.

Total Assets

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.

Total assets as at December 31, 2016 decreased compared to December 31, 2015 primarily due to an increase in depletion and depreciation expense as a result of an increase in the estimated future development costs associated with the Corporation's proved reserves, and a decrease in cash and cash equivalents. The cash and cash equivalents balance as at December 31, 2016 decreased compared to December 31, 2015 primarily due to the use of cash for interest and principal payments and payments relating to capital investing activities.

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, 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.

Total non-current liabilities as at December 31, 2016 decreased compared to December 31, 2015 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 3% during the year ended December 31, 2016. In addition, the Corporation recognized a deferred income tax asset as at December 31, 2016 compared to a deferred income tax liability as at December 31, 2015.

LIQUIDITY AND CAPITAL RESOURCES

($000)	**December 31, 2017**	**December 31, 2016**
Cash and cash equivalents	**$ 463,531**	$ 156,230
Senior secured term loan (December 31, 2017 – US$1.226 billion; due 2023; December 31, 2016 – US$1.236 billion)	**1,534,378**	1,658,906
US$1.4 billion revolving credit facility (due 2021)	**-**	-
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**938,850**	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	**-**	1,007,025
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,001,440**	1,074,160
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,251,800**	1,342,700
Total debt[1]	**$ 4,726,468**	$ 5,082,791

(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.

Capital Resources

The Corporation's cash and cash equivalents balance totalled $463.5 million as at December 31, 2017 compared to $156.2 million as at December 31, 2016. The increase is primarily due to net cash provided by operating activities of $317.9 million, net equity issuance proceeds of $496.3 million received pursuant to the comprehensive refinancing that closed on January 27, 2017, partially offset by net cash used in investing activities of $405.2 million.

All of the Corporation's long-term debt is denominated in U.S. dollars. 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. Primarily as a result of the increase in the value of the Canadian dollar relative to the U.S. dollar, long-term debt decreased to C$4.67 billion as at December 31, 2017 from C$5.05 billion as at December 31, 2016.

On January 27, 2017, the Corporation closed a comprehensive refinancing plan by way of the Corporation's Canadian base shelf prospectus dated December 1, 2016. The plan was comprised of the following four transactions:

- An extension of the maturity date on substantially all of the commitments under the Corporation's undrawn 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. The revolving credit facility has no financial maintenance covenants and is not subject to any borrowing base redetermination;
- The US$1.2 billion term loan has been refinanced and its maturity date has been extended from March 2020 to December 2023. The refinanced term loan bears interest at an annual rate of LIBOR plus 3.5% with a LIBOR floor of 1%;
- The US$750 million aggregate principal amount of 6.5% Senior Unsecured Notes, with a maturity date of March 2021, have been refinanced and replaced with new 6.5% Senior Secured Second Lien Notes, maturing January 2025. The existing 2021 notes were redeemed with the proceeds from the Senior Secured Second Lien Notes on March 15, 2017; and
- The Corporation raised C$518 million of equity, before underwriting fees and expenses, in the form of 66,815,000 common shares at a price of $7.75 per common share on a bought deal basis from a syndicate of underwriters.

In addition to the transactions noted above, on February 15, 2017, the Corporation extended the maturity date on its five-year letter of credit facility, guaranteed by Export Development Canada ("EDC"), 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, 2017, letters of credit of US$258 million were issued and outstanding under this facility.

On February 8, 2018 the Corporation announced that it had entered into an agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of MEG's senior secured term loan.

All of MEG's long-term debt, the revolving credit facility and the EDC 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 commodity prices and market conditions 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.

The Corporation had the following financial commodity risk management contracts relating to crude oil sales outstanding:

As at December 31, 2017	Volumes (bbls/d)(1)	Term	Average Price (US$/bbl)(1)
Fixed Price:			
WTI Fixed Price	30,700	Jan 1, 2018 – Jun 30, 2018	$52.89
WTI Fixed Price	22,500	Jul 1, 2018 – Dec 31, 2018	$52.72
WTI:WCS Fixed Differential	48,700	Jan 1, 2018 – Jun 30, 2018	$(14.43)
WTI:WCS Fixed Differential	32,000	Jul 1, 2018 – Dec 31, 2018	$(14.68)
Collars:			
WTI Collars	41,500	Jan 1, 2018 – Jun 30, 2018	$46.71 – $54.97
WTI Collars	32,500	Jul 1, 2018 – Dec 31, 2018	$46.64 – $54.52

The Corporation has entered into the following commodity risk management contracts relating to crude oil sales subsequent to December 31, 2017 up to the date of March 8, 2018:

Subsequent to December 31, 2017	Volumes (bbls/d)(1)	Term	Average Price (US$/bbl)(1)
Fixed Price:			
WTI Fixed Price	3,000	Apr 1, 2018 – Jun 30, 2018	$63.82
WTI Fixed Price	11,500	Jul 1, 2018 – Dec 31, 2018	$60.20

The Corporation has entered into the following financial commodity risk management contracts relating to condensate purchases subsequent to December 31, 2017 up to the date of March 8, 2018:

Subsequent to December 31, 2017	Volumes (bbls/d)(1)	Term	Average % of WTI(1)
Mont Belvieu fixed % of WTI	1,000	Apr 1, 2018 – Jun 30, 2018	92.3%
Mont Belvieu fixed % of WTI	500	Jul 1, 2018 – Sep 30, 2018	93.5%

(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 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 at approximately 5.3% on US$650.0 million of the US$1.2 billion senior secured term loan from September 29, 2017 to December 31, 2020. During the first nine months of 2016, the Corporation had interest rate swap contracts in place to effectively fix the interest rate at approximately 4.4% on US$748.0 million of the senior secured term loan. These interest rate swap contracts expired on September 30, 2016.

Cash Flow Summary

($000)	2017	2016
Net cash provided by (used in):		
Operating activities	**$ 317,935**	$ (94,074)
Investing activities	**(405,231)**	(131,111)
Financing activities	**401,245**	(17,062)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(6,648)**	(9,736)
Change in cash and cash equivalents	**$ 307,301**	$ (251,983)

Cash Flow – Operating Activities

Net cash provided by operating activities totalled $317.9 million for the year ended December 31, 2017 compared to net cash used in operating activities of $94.1 million for the year ended December 31, 2016. This increase in cash flows is primarily due to higher bitumen realization, primarily as a result of the increase in average crude oil benchmark pricing.

Cash Flow – Investing Activities

Net cash used in investing activities was $405.2 million for the year ended December 31, 2017 compared to $131.1 million for the year ended December 31, 2016. The increase in capital investment in 2017 has been primarily directed towards the Corporation's eMSAGP production growth initiative at Christina Lake Phase 2B and sustaining capital activities.

Cash Flow – Financing Activities

Net cash provided by financing activities was $401.2 million for the year ended December 31, 2017 compared to net cash used in financing activities of $17.1 million for the year ended December 31, 2016. Net cash provided by financing activities increased primarily due to net equity issuance proceeds as part of the comprehensive refinancing plan that closed on January 27, 2017. Net cash used in financing activities also includes debt principal payments of $12.7 million.

SHARES OUTSTANDING

As at December 31, 2017, the Corporation had the following share capital instruments outstanding or exercisable:

(000)	Outstanding
Common shares	**294,104**
Convertible securities	
Stock options[1]	**8,896**
Equity-settled RSUs and PSUs	**6,307**

(1) 6.2 million stock options were exercisable as at December 31, 2017.

On January 27, 2017, the Corporation issued 66.8 million common shares at a price of $7.75 per common share.

As at March 7, 2018, the Corporation had 294.1 million common shares, 8.8 million stock options and 6.3 million equity-settled restricted share units and equity-settled performance share units outstanding, and 6.1 million stock options exercisable.

The Corporation's common shares have increased as a result of the issuance of 66.8 million common shares pursuant to the $518 million equity issuance which closed on January 27, 2017 as outlined in the "Capital Resources" section of this MD&A.

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, 2017 and excludes any impact related to transactions that occurred subsequent to December 31, 2017 as described in the "SUBSEQUENT EVENTS" section. 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)	2018	2019	2020	2021	2022	Thereafter	Total
Long-term debt(1)	$ 15,460	$ 15,460	$ 15,460	$ 15,460	$ 15,460	$ 4,649,168	$ 4,726,468
Interest on long-term debt(1)	292,046	291,243	290,439	289,634	288,830	317,522	1,769,714
Decommissioning obligation(2)	6,386	9,811	7,435	8,614	8,614	818,268	859,128
Transportation and storage(3)	169,248	182,850	227,393	283,457	284,128	2,248,252	3,395,328
Office lease rentals	10,863	10,863	11,286	11,286	11,286	107,667	163,251
Diluent purchases(4)	483,812	19,563	19,617	19,563	19,563	16,294	578,412
Other commitments(5)	47,834	22,862	21,304	20,017	18,106	105,093	235,216
Total	**$ 1,025,649**	**$ 552,652**	**$ 592,934**	**$ 648,031**	**$ 645,987**	**$ 8,262,264**	**$ 11,727,517**

(1) 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, 2017.

(2) This represents the undiscounted future obligations associated with the decommissioning of the Corporation's crude oil, transportation and storage assets.

(3) This represents transportation and storage commitments from 2018 to 2039, including various pipeline commitments which are awaiting regulatory approval and are not yet in service.

(4) This represents the future commitments associated with the Corporation's diluent purchases.

(5) This represents the future commitments associated with the Corporation's capital program, other operating and maintenance commitments, and estimated net payments related to onerous lease contracts.

(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. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation continues to view this three year old claim, and the recent amendments, as without merit and will defend against all such claims.

SUBSEQUENT EVENTS

On February 7, 2018, the Corporation entered into an agreement with Wolf Midstream Inc. ("Wolf") for the sale of the Corporation's 50% interest in Access Pipeline and its 100% interest in the Stonefell Terminal for cash and other consideration of $1.61 billion ("the transaction"). The transaction was announced on February 8, 2018.

As part of the transaction, the Corporation and Wolf have entered into a Transportation Services Agreement dedicating the Corporation's Christina Lake production and condensate transport to 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 the Corporation's operational control and exclusive use of 100% of Stonefell Terminal's 900,000 barrel blend and condensate storage facility. The sale of the Stonefell Terminal and the Stonefell Lease Agreement will be accounted for as a sale and leaseback transaction that results in a finance lease.

The Corporation will receive $1.52 billion in cash at closing, and a credit of $90 million toward future expansions of Access Pipeline whereby the Corporation will not pay incremental tolls to fund such expansions. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of MEG's senior secured term loan.

As a result of the transaction announced on February 8, 2018, the Corporation determined that the expected repayment of debt results in a change in estimated life of certain amounts associated with the senior secured term loan. A debt extinguishment expense of $30.8 million was recorded at December 31, 2017, as an adjusting subsequent event under IAS 10, Events after the Reporting Period.

The transaction is expected to close in the first quarter of 2018, subject to regulatory approvals and customary closing conditions.

Subsequent to entering into the agreement, the Corporation entered into forward currency contracts to manage the foreign exchange risk on the Canadian dollar denominated proceeds from the sale of assets designated for U.S. dollar denominated long-term debt repayment.

NON-GAAP MEASURES

Certain financial measures in this MD&A including: net marketing activity, funds flow from (used in) operations, adjusted funds flow from (used in) operations, operating earnings (loss), operating cash flow 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 purchased product and storage arrangements. Petroleum revenue – third party is disclosed in Note 17 in the Notes to the Consolidated Financial Statements and purchased product and storage is presented as a line item on the Consolidated Statement of Earnings and Comprehensive Income.

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

Funds flow from (used in) operations and adjusted funds flow from (used in) operations 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 from (used in) operations excludes the net change in non-cash operating working capital, 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 from (used in) operations 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 from (used in) operations are reconciled to net cash provided by (used in) operating activities in the table below.

($000)		2017		2016
Net cash provided by (used in) operating activities	**$**	**317,935**	$	(94,074)
Net change in non-cash operating working capital items		**24,517**		25,061
Funds flow from (used in) operations		**342,452**		(69,013)
Adjustments:				
Contract cancellation expense		**18,765**		-
Net change in other liabilities		**(9,389)**		-
Payments on onerous contracts		**19,569**		6,116
Decommissioning expenditures		**2,403**		1,290
Adjusted funds flow from (used in) operations	**$**	**373,800**	$	(61,607)

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, impairment charge, contract cancellation expense, onerous contracts 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, in the table below.

($000)		2017		2016
Net earnings (loss)	**$**	**165,976**	$	(428,726)
Adjustments:				
Unrealized net loss (gain) on foreign exchange[(1)]		**(338,144)**		(148,153)
Unrealized loss (gain) on derivative financial liabilities[(2)]		**(16,179)**		(12,508)
Unrealized loss (gain) on commodity risk management[(3)]		**38,336**		30,313
Impairment charge[(4)]		**-**		80,072
Contract cancellation expense[(5)]		**18,765**		-
Onerous contracts expense[(6)]		**10,830**		47,866
Debt extinguishment expense[(7)]		**30,801**		28,845
Insurance proceeds		**(183)**		(4,391)
Deferred tax expense (recovery) relating to these adjustments		**(23,726)**		(48,416)
Operating earnings (loss)	**$**	**(113,524)**	$	(455,098)

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

(2) Unrealized gains and losses on derivative financial liabilities result 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 the unsettled commodity risk management contracts during the period.

(4) During the fourth quarter of 2016, the Corporation recognized an impairment charge of $80.1 million relating to an investment in the right to participate in the Northern Gateway pipeline.

(5) 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 transportation contract.

(6) *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.*

(7) *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. At December 31, 2016, the Corporation recognized $28.8 million of debt extinguishment expense associated with the planned redemption of the 6.5% Senior Unsecured Notes on March 15, 2017, under the comprehensive refinancing plan completed on January 27, 2017.*

Operating Cash Flow

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, transportation, field operating costs, 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, 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, excluding the debt redemption premium, 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, 2017	December 31, 2016
Long-term debt	$ 4,668,267	$ 5,053,239
Adjustments:		
Debt redemption premium	-	(21,812)
Current portion of senior secured term loan	15,460	17,455
Unamortized financial derivative liability discount	4,242	11,143
Unamortized deferred debt discount and debt issue costs	38,499	22,766
Total debt	$ 4,726,468	$ 5,082,791

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

Items of property, plant and equipment, including oil sands property and equipment, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Capitalized costs associated with the Corporation's field production assets, including estimated future development costs, are depleted using the unit-of-production method based on estimated proved reserves. The Corporation's oil sands facilities are depreciated on a unit-of-production method based on the facilities' productive capacity over their estimated remaining useful lives. The costs associated with the Corporation's interest in transportation and storage assets are depreciated on a straight-line basis over the estimated remaining useful lives of the assets. The determination of future development costs, proved reserves, productive capacity and remaining useful lives are subject to significant judgments and estimates.

Exploration and Evaluation Assets

Pre-exploration costs incurred before the Corporation obtains the legal right to explore an area are expensed. Exploration and evaluation costs associated with the Corporation's oil sands activities are capitalized. These costs are accumulated in cost centres pending determination of technical feasibility and commercial viability at which point the costs are transferred to property, plant and equipment. If it is determined that an exploration and evaluation asset is not technically feasible or commercially viable and the Corporation decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to expense. 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. The determination of proved or probable reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Impairments

The carrying amounts of the Corporation's non-financial 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. An impairment test is completed each year for intangible assets that are not yet available for use. Exploration and evaluation assets are assessed for impairment when they are reclassified to property, plant and equipment or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, property, plant and equipment assets are grouped into cash-generating units ("CGUs"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal. Exploration and evaluation assets are assessed for impairment within the aggregation of all CGUs in that segment.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. 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 if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized within net earnings during the period in which they arise. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the CGU on a pro-rata basis.

Impairment losses recognized in prior years 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.

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. The Corporation's reserves estimates are evaluated annually by independent qualified reserve evaluators.

Joint Operations

Judgment is required to determine whether an interest the Corporation holds in a joint arrangement should be classified as a joint operation or joint venture. The determination includes an assessment as to whether the Corporation has the rights to the assets and obligations for the liabilities of the arrangement or the rights to the net assets. The Corporation holds an undivided interest in Access Pipeline. As a result, the Corporation presents its proportionate share of the assets, liabilities, revenues and expenses of Access Pipeline on a line-by-line basis in the consolidated financial statements.

Decommissioning Provision

The Corporation recognizes an asset and a liability for any existing decommissioning obligations associated with the dismantling, decommissioning and restoration of property, plant and equipment and exploration and evaluation assets. The provision is determined by estimating the fair value of the decommissioning obligation at the end of the period. This fair value is determined by estimating expected timing and cash flows that will be required for future dismantlement and site restoration, and then calculating the present value of these future payments using a credit-adjusted risk-free rate specific to the liability. Any change in timing or amount of the cash flows subsequent to initial recognition results in a change in the asset and liability, which then impacts the depletion and depreciation on the asset and accretion charged on the liability. Estimating the timing and amount of third party cash flows to settle these obligations is inherently difficult and is based on third party estimates and management's experience.

Onerous Contracts

The Corporation recognizes a provision for onerous contracts 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. The provision is determined by estimating the present value of the minimum future contractual payments that the Corporation is obligated to make under the non-cancellable onerous contracts reduced by estimated recoveries.

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 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. 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. 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.

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.

Derivative Financial Instruments

The Corporation may utilize derivative financial instruments to manage commodity price, foreign currency and interest rate exposures. These financial instruments are not used for trading or speculative purposes. The fair values of derivative financial instruments are estimated at the end of each reporting period based on expectations of future cash flows associated with the derivative instrument. Estimates of future cash flows are based on forecast commodity prices, interest rates and foreign exchange rates expected to be in effect over the remaining life of the contract. Any subsequent changes in these rates will impact the amounts ultimately recognized in relation to the derivative instruments.

TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any significant related party transactions during the year ended December 31, 2017 and December 31, 2016, other than compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($000)		**2017**		**2016**
Salaries and short-term employee benefits	**$**	**7,385**	$	9,117
Share-based compensation		**9,578**		12,006
Termination benefits		**64**		1,617
	$	**17,027**	$	22,740

OFF-BALANCE SHEET ARRANGEMENTS

As at December 31, 2017 and December 31, 2016, 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, 2017 and December 31, 2016.

NEW ACCOUNTING STANDARDS

The Corporation has adopted the following revised standards during the year ended December 31, 2017:

IAS 7, Statement of Cash Flows, has been amended by the IASB as part of its disclosure initiative to require additional disclosure for changes in liabilities arising from financing activities. This includes changes arising from cash flows and non-cash changes. Additional disclosures for changes in liabilities arising from financing activities have been included in Note 25 to the Corporation's consolidated financial statements. As allowed by IAS 7, comparative information has not been presented.

IAS 12, Income Taxes, has been amended to clarify the recognition of deferred tax assets relating to unrealized losses. The adoption of this revision did not have an 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 accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, but disclosure requirements are enhanced. 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. The Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements and is in the process of planning and identifying leases that are within the scope of the standard. The Corporation anticipates there will be a material impact on the consolidated financial statements and additional new disclosures.

IFRS 9 Financial Instruments

In July 2014, the IASB issued IFRS 9 Financial Instruments, which is intended to replace 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 aligns with risk management activities. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The adoption of these changes will not have a material impact on the Corporation's consolidated financial statements.

A new 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 Corporation is currently assessing and evaluating the impact of the new amendment. IFRS 9 will be adopted by the Corporation on January 1, 2018, as required by the standard, on a modified retrospective basis.

IFRS 15 Revenue From Contracts With Customers

In May 2014, the IASB issued IFRS 15 Revenue From Contracts With Customers, which will replace 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 new standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The Corporation will be adopting IFRS 15 retrospectively on January 1, 2018. The Corporation has substantially completed its assessment and evaluation of the underlying terms of its revenue contracts with customers and has determined that adoption of the standard will not have a material impact on the Corporation's consolidated financial statements. The Corporation anticipates there will be additional enhanced disclosures.

IFRS 2 Share-based Payment

In June 2016, the IASB issued amendments to IFRS 2 Share-based Payment, relating to classification and measurement of particular share-based payment transactions. The amendments are effective for periods beginning on or after January 1, 2018, and will be applied prospectively as required by the standard. The Corporation anticipates that the adoption of these amendments will not have a material impact on the Corporation's consolidated financial statements.

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, 2017 and a preparation date of February 9, 2018 ("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, 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.

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 and the CCIR 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 October 2016, the Government of Canada announced that it would implement a national price on carbon (the "Pan-Canadian Carbon Plan") in response to the Paris Agreement. Under the Pan-Canadian Carbon Plan, the federal government is proposing 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 Pan-Canadian Carbon Plan will allow provinces to implement either a carbon tax or use a broad market based mechanism. The Pan-Canadian Carbon

Plan includes a federal backstop in the event jurisdictions do not meet the floor carbon price. On January 15, 2018 the Government of Canada released draft legislative proposals for the federal backstop. The proposed Greenhouse Gas Pollution Pricing Act, which is similar in structure to Alberta's approach to carbon pricing, includes a levy on fossil fuels and an output-based pricing system for industrial facilities. The federal government's proposed legislation would apply, 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. The federal government has requested that a province opting to establish or maintain a provincial carbon pricing system must outline its system by September 1, 2018, after which the federal government will confirm whether the provincial carbon pricing system meets the federal standard. The federal government will implement the proposed federal legislation in whole or in part on January 1, 2019 in any province that does not have a carbon pricing system that meets the federal standard. It is uncertain at this time if Alberta will be subject to the proposed Greenhouse Gas Pollution Pricing Act; however, it is expected Alberta will attempt to make the case that Alberta's approach to carbon pricing is equivalent to the federal standard and as a result the proposed federal legislation may 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 2017, none of MEG's oil sand leases expired and MEG received indefinite continuations on 7 leases at Christina Lake and the May River Regional Project with 2017 expiry dates. MEG's oil sands leases scheduled to expire in 2018 and located at Christina Lake and the May River Regional Project have obtained indefinite continuations or have received pre-determinations for indefinite continuation. MEG has received pre-determinations for indefinite continuation on two Surmont oil sand leases expiring in 2019. MEG will apply for pre-determinations or continuations for the remaining oil sands leases at Surmont when appropriate.

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 2018 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 addition, Alberta Energy has recently offered the ability for lessees to apply for further lease extensions to March 31, 2019 for leases that fall within designated caribou ranges.

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.

Possible Failure to Complete Sale of Access Pipeline and Stonefell Terminal

The sale of the Access Pipeline and Stonefell Terminal is subject to the normal commercial risks that the transaction will not close on the terms specified or at all. The completion of the sale is subject to satisfaction or waiver of a number of conditions, certain of which have not been satisfied or waived as of the date of this MD&A. Accordingly, there can be no assurance that the Corporation will complete the sale of the Access Pipeline and Stonefell Terminal in the timeframe or on the basis described herein, or at all. A failure to complete the sale of the Access Pipeline and Stonefell Terminal or a substantial delay in obtaining necessary approvals could have a material adverse effect on the Corporation's ability to complete the sale and on the Corporation's business, financial condition or results of operations.

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 are effective at December 31, 2017 for the foregoing purposes.

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, 2017.

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.

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
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

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; and anticipated sources of funding for operations and capital investments. 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; 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

For information regarding MEG's estimated reserves, 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 from (used in) operations, 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.

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.

QUARTERLY SUMMARIES

	2017				2016			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL ($000 unless specified)								
Net earnings (loss)	**(23,779)**	83,885	104,282	1,588	(304,758)	(108,632)	(146,165)	130,829
Per share, diluted	**(0.08)**	0.28	0.35	0.01	(1.34)	(0.48)	(0.65)	0.58
Operating earnings (loss)	**44,055**	(42,571)	(35,656)	(79,354)	(71,989)	(87,929)	(97,894)	(197,286)
Per share, diluted	**0.15**	(0.14)	(0.12)	(0.29)	(0.32)	(0.39)	(0.43)	(0.88)
Adjusted funds flow from (used in) operations	**192,178**	83,352	55,095	43,175	39,967	22,702	6,964	(131,240)
Per share, diluted	**0.65**	0.28	0.19	0.16	0.18	0.10	0.03	(0.58)
Cash capital investment	**163,337**	103,173	158,474	77,770	63,077	19,203	19,990	34,975
Cash and cash equivalents	**463,531**	397,598	512,424	548,981	156,230	103,136	152,711	124,560
Working capital	**313,025**	350,067	445,463	537,427	96,442	163,038	128,586	183,649
Long-term debt	**4,668,267**	4,635,740	4,813,092	4,944,741	5,053,239	4,909,711	4,871,182	4,859,099
Shareholders' equity	**3,964,113**	3,981,750	3,898,054	3,792,818	3,286,776	3,577,557	3,679,372	3,812,566
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**55.40**	48.21	48.29	51.91	49.29	44.94	45.59	33.45
C$ equivalent of 1US$ - average	**1.2717**	1.2524	1.3449	1.3230	1.3339	1.3051	1.2886	1.3748
Differential – WTI:WCS (C$/bbl)	**15.59**	12.45	14.97	19.29	19.10	17.62	17.14	19.58
Differential – WTI:WCS (%)	**22.1%**	20.6%	23.0%	28.1%	29.1%	30.0%	29.2%	42.6%
Natural gas – AECO ($/mcf)	**1.84**	1.58	2.81	2.91	3.31	2.49	1.37	1.82
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**90,228**	83,008	72,448	77,245	81,780	83,404	83,127	76,640
Bitumen sales – bbls/d	**94,541**	76,813	74,116	74,703	81,746	84,817	80,548	74,529
Steam-oil ratio (SOR)	**2.2**	2.3	2.3	2.4	2.3	2.2	2.3	2.4
Bitumen realization	**48.30**	39.89	39.66	37.93	36.17	30.98	30.93	11.43
Transportation – net	**(7.00)**	(7.08)	(6.91)	(6.54)	(6.05)	(6.46)	(6.66)	(6.68)
Royalties	**(0.84)**	(0.53)	(0.87)	(0.85)	(0.51)	(0.42)	(0.27)	0.07
Operating costs – non-energy	**(4.53)**	(4.57)	(4.23)	(5.20)	(4.99)	(5.32)	(5.81)	(6.45)
Operating costs – energy	**(2.03)**	(2.26)	(3.76)	(4.18)	(4.12)	(2.99)	(1.97)	(2.90)
Power revenue	**0.70**	0.83	0.57	0.95	0.87	0.55	0.35	0.82
Realized gain (loss) on commodity risk management	**(0.77)**	0.56	(1.50)	0.22	0.36	0.40	(0.48)	-
Cash operating netback	**33.83**	26.84	22.96	22.33	21.73	16.74	16.09	(3.71)
Power sales price (C$/MWh)	**21.37**	23.29	18.27	22.42	21.94	17.62	13.54	19.77
Power sales (MW/h)	**129**	115	97	131	134	110	86	129
Depletion and depreciation rate per bbl of production	**14.26**	16.86	16.93	16.81	16.81	16.81	16.84	16.78
COMMON SHARES								
Shares outstanding, end of period (000)	**294,104**	294,079	294,047	293,282	226,467	226,415	226,357	224,997
Volume traded (000)	**76,531**	70,216	98,795	123,445	114,776	112,720	157,056	182,199
Common share price ($)								
High	**6.82**	5.79	7.27	9.83	9.79	6.90	7.86	8.26
Low	**4.54**	3.28	3.63	5.84	5.11	4.72	5.21	3.46
Close (end of period)	**5.14**	5.49	3.81	6.74	9.23	5.93	6.84	6.55

ANNUAL SUMMARIES

Unaudited	2017	2016	2015	2014	2013	2012
FINANCIAL ($000 unless specified)						
Net earnings (loss)	**165,976**	(428,726)	(1,169,671)	(105,538)	(166,405)	52,569
Per share, diluted	**0.57**	(1.90)	(5.21)	(0.47)	(0.75)	0.26
Operating earnings (loss)	**(113,524)**	(455,098)	(374,374)	247,353	386	21,242
Per share, diluted	**(0.39)**	(2.01)	(1.67)	1.10	0.00	0.11
Adjusted funds flow from (used in) operations	**373,800**	(61,607)	49,460	791,458	253,424	212,514
Per share, diluted	**1.29**	(0.27)	0.22	3.52	1.13	1.06
Cash capital investment	**502,754**	137,245	257,178	1,237,539	2,111,824	1,567,906
Cash and cash equivalents	**463,531**	156,230	408,213	656,097	1,179,072	1,474,843
Working capital	**313,025**	96,442	363,038	525,534	1,045,606	1,655,915
Long-term debt	**4,668,267**	5,053,239	5,190,363	4,350,421	3,990,748	2,478,660
Shareholders' equity	**3,964,113**	3,286,776	3,677,867	4,768,235	4,788,430	4,870,534
BUSINESS ENVIRONMENT						
WTI (US$/bbl)	**50.95**	43.33	48.80	93.00	97.96	94.21
C$ equivalent of 1US$ - average	**1.2980**	1.3256	1.2788	1.1047	1.0296	0.9994
Differential – WTI:WCS ($/bbl)	**15.55**	18.35	17.29	21.63	25.89	21.01
Differential – WTI:WCS (%)	**23.5%**	31.9%	27.7%	21.1%	25.7%	22.3%
Natural gas – AECO ($/mcf)	**2.29**	2.25	2.71	4.50	3.16	2.38
OPERATIONAL ($/bbl unless specified)						
Bitumen production – bbls/d	**80,774**	81,245	80,025	71,186	35,317	28,773
Bitumen sales – bbls/d	**80,089**	80,426	80,965	67,243	33,715	28,845
Steam-oil ratio (SOR)	**2.3**	2.3	2.5	2.5	2.6	2.4
Bitumen realization	**41.89**	27.79	30.63	62.67	49.28	46.93
Transportation – net	**(6.89)**	(6.46)	(4.82)	(1.38)	(0.26)	(0.31)
Royalties	**(0.77)**	(0.29)	(0.70)	(4.36)	(3.14)	(2.46)
Operating costs – non-energy	**(4.62)**	(5.62)	(6.54)	(8.02)	(9.00)	(9.71)
Operating costs – energy	**(2.98)**	(3.01)	(3.84)	(6.30)	(4.62)	(3.46)
Power revenue	**0.76**	0.64	0.99	2.26	3.61	3.19
Realized gain (loss) on commodity risk management	**(0.39)**	0.08	-	-	-	-
Cash operating netback	**27.00**	13.13	15.72	44.87	35.87	34.18
Power sales price (C$/MWh)	**21.49**	18.74	27.48	48.83	76.23	59.22
Power sales (MW/h)	**118**	115	121	129	67	65
Depletion and depreciation rate per bbl of production	**16.13**	16.81	16.00	14.57	14.67	13.76
COMMON SHARES						
Shares outstanding, end of period (000)	**294,104**	226,467	224,997	223,847	222,507	220,190
Volume traded (000)	**368,987**	566,751	248,316	227,538	134,087	73,738
Common share price ($)						
High	**9.83**	9.79	25.20	41.29	36.69	47.11
Low	**3.28**	3.46	7.33	13.30	25.50	30.25
Close (end of period)	**5.14**	9.23	8.02	19.55	30.61	30.44

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, 2017.

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, 2017. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

Bill McCaffrey

William (Bill) McCaffrey, P.Eng.
President and Chief Executive Officer

Eric L. Toews, CPA, CA
Chief Financial Officer

MARCH 8, 2018

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF MEG ENERGY CORP.

We have audited the accompanying consolidated financial statements of MEG Energy Corp. and its subsidiaries, which comprise the consolidated balance sheet as at December 31, 2017 and December 31, 2016 and the consolidated statements of earnings (loss) and comprehensive income (loss), changes in shareholders' equity and cash flow for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, 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.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of MEG Energy Corp. and its subsidiaries as at December 31, 2017 and December 31, 2016 and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta

MARCH 8, 2018

CONSOLIDATED BALANCE SHEET

(Expressed in thousands of Canadian dollars)

As at December 31	Note	2017	2016
Assets			
Current assets			
Cash and cash equivalents	25	**$ 463,531**	$ 156,230
Trade receivables and other	5	**289,104**	236,989
Inventories	6	**85,850**	66,394
		838,485	459,613
Non-current assets			
Property, plant and equipment	7	**7,634,399**	7,639,434
Exploration and evaluation assets	8	**548,828**	547,752
Intangible assets	9	**13,037**	16,111
Other assets	10	**145,732**	137,370
Deferred income tax asset	14	**182,871**	120,944
Total assets		**$ 9,363,352**	$ 8,921,224
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	11	**$ 413,905**	$ 292,340
Current portion of long-term debt	12	**15,460**	17,455
Current portion of provisions and other liabilities	13	**27,446**	23,063
Commodity risk management	27	**68,649**	30,313
		525,460	363,171
Non-current liabilities			
Long-term debt	12	**4,668,267**	5,053,239
Provisions and other liabilities	13	**205,512**	218,038
Total liabilities		**5,399,239**	5,634,448
Shareholders' equity			
Share capital	15	**5,403,978**	4,878,607
Contributed surplus		**166,636**	168,253
Deficit		**(1,629,091)**	(1,795,067)
Accumulated other comprehensive income		**22,590**	34,983
Total shareholders' equity		**3,964,113**	3,286,776
Total liabilities and shareholders' equity		**$ 9,363,352**	$ 8,921,224

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 8, 2018.

Bill McCaffrey

William (Bill) McCaffrey, Director

Robert B. Hodgins

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	Note	2017	2016
Revenues			
Petroleum revenue, net of royalties	17	**$ 2,399,510**	$ 1,823,234
Other revenue	18	**35,193**	43,050
		2,434,703	1,866,284
Expenses			
Diluent and transportation	19	**1,158,414**	1,017,894
Operating expenses	23	**222,196**	253,758
Purchased product and storage		**250,681**	202,135
Depletion and depreciation	7,9	**475,644**	499,811
Impairment charge	9	**-**	80,072
Exploration expense	8	**-**	1,248
General and administrative	23	**86,785**	96,241
Stock-based compensation	16	**22,528**	49,942
Research and development		**5,808**	5,499
Net finance expense	21	**361,080**	355,323
Other expenses	22	**34,726**	64,022
Commodity risk management loss (gain)	27	**49,609**	27,954
Foreign exchange loss (gain), net	20	**(342,547)**	(151,395)
Earnings (loss) before income taxes		**109,779**	(636,220)
Income tax recovery	14	**(56,197)**	(207,494)
Net earnings (loss)		**165,976**	(428,726)
Other comprehensive income (loss), net of tax			
Items that may be reclassified to profit or loss:			
Foreign currency translation adjustment		**(12,393)**	(590)
Comprehensive income (loss)		**$ 153,583**	$ (429,316)
Net earnings (loss) per common share			
Basic	26	**$ 0.57**	$ (1.90)
Diluted	26	**$ 0.57**	$ (1.90)

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, 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**
Balance as at December 31, 2015		$ 4,836,800	$ 171,835	$ (1,366,341)	$ 35,573	$ 3,677,867
Stock-based compensation	16	-	38,225	-	-	38,225
RSUs vested and released	15	41,807	(41,807)	-	-	-
Comprehensive income (loss)		-	-	(428,726)	(590)	(429,316)
Balance as at December 31, 2016		$ 4,878,607	$ 168,253	$ (1,795,067)	$ 34,983	$ 3,286,776

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	2017	2016
Cash provided by (used in):			
Operating activities			
Net earnings (loss)		**$ 165,976**	$ (428,726)
Adjustments for:			
Depletion and depreciation	7,9	**475,644**	499,811
Impairment charge	9	**-**	80,072
Exploration expense	8	**-**	1,248
Stock-based compensation	16	**19,052**	33,588
Unrealized loss (gain) on foreign exchange	20	**(338,144)**	(148,153)
Unrealized loss (gain) on derivative financial liabilities	21	**(16,179)**	(12,508)
Unrealized loss (gain) on risk management	27	**38,336**	30,313
Onerous contracts expense	22	**10,830**	47,866
Deferred income tax recovery	14	**(56,130)**	(208,413)
Amortization of debt discount and debt issue costs	10,12	**19,225**	12,192
Debt extinguishment expense	12,21	**30,801**	28,845
Other		**5,624**	2,258
Decommissioning expenditures	13	**(2,403)**	(1,290)
Payments on onerous contracts	13	**(19,569)**	(6,116)
Net change in other liabilities		**9,389**	-
Net change in non-cash working capital items	25	**(24,517)**	(25,061)
Net cash provided by (used in) operating activities		**317,935**	(94,074)
Investing activities			
Capital investments:			
Property, plant and equipment	7	**(505,713)**	(120,828)
Exploration and evaluation	8	**(1,569)**	(2,265)
Intangible assets	9	**(534)**	(16,643)
Proceeds on dispositions	7,8	**5,370**	3,247
Deferred lease inducements and other	13	**20,983**	2,775
Net change in non-cash working capital items	25	**76,232**	2,603
Net cash provided by (used in) investing activities		**(405,231)**	(131,111)
Financing activities			
Issue of shares, net of issue costs	25	**496,312**	-
Redemption of senior unsecured notes	25	**(1,008,825)**	-
Issue of senior secured second lien notes	25	**1,008,825**	-
Payments on term loan	12	**(12,690)**	(17,062)
Refinancing costs	25	**(82,377)**	-
Net cash provided by (used in) financing activities		**401,245**	(17,062)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	20	**(6,648)**	(9,736)
Change in cash and cash equivalents		**307,301**	(251,983)
Cash and cash equivalents, beginning of year	25	**156,230**	408,213
Cash and cash equivalents, end of year	25	**$ 463,531**	$ 156,230

The accompanying notes are an integral part of these consolidated financial statements.

Notes to Consolidated Financial Statements

YEAR ENDED DECEMBER 31, 2017

(All amounts are expressed in thousands of Canadian dollars, unless otherwise noted.)

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. The Corporation also holds a 50% interest in the Access Pipeline, a dual pipeline to transport diluent north from the Edmonton area to the Athabasca oil sands area and a blend of bitumen and diluent south from the Christina Lake Project into the Edmonton area. In addition to the Access Pipeline, the Corporation owns the Stonefell Terminal, located near Edmonton, Alberta, which offers 900,000 barrels of terminalling and storage capacity. The Stonefell Terminal is connected to the Access Pipeline and is also connected by pipeline to a third party rail-loading terminal.

On February 7, 2018, the Corporation entered into an agreement for the sale of the Corporation's 50% interest in Access Pipeline and its 100% interest in the Stonefell Terminal. The transaction is expected to close in the first quarter of 2018, subject to regulatory approvals and customary closing conditions (Note 32).

The corporate office is located at 600 – 3rd Avenue S.W., 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 8, 2018.

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.

The Corporation owns an undivided 50% working interest in Access Pipeline and is responsible for its proportionate ownership interest of all assets and liabilities and other obligations. Since the Corporation owns an undivided interest in Access Pipeline, it holds a proportionate share of the rights to the assets and obligations for the liabilities. As a result, the Corporation presents its proportionate share of the assets, liabilities, revenues and expenses of Access Pipeline on a line-by-line basis in the 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

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.

(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.

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.

(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 – long-term 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 long-term 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) Leased assets

Leases where the Corporation assumes substantially all the risks and rewards of ownership are classified as finance leases within PP&E. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum 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. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the fair value or estimated future cash flows of an asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Impairment losses are recognized in earnings or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

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. Emission 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

i. Petroleum revenue and royalties

Revenue associated with the sale of proprietary and purchased crude oil and natural gas is recognized when title passes from the Corporation to its customers and collection is reasonably assured. Royalties are recorded at the time of production.

ii. Other revenue

Revenue from power generated in excess of the Corporation's internal requirements is recognized when the power leaves the plant gate, at which point the risks and rewards are transferred to the customer. Revenue generated from the transportation of crude oil products is recognized in the period the product is delivered and the service is provided.

(s) Diluent and transportation

The costs associated with the transportation of crude oil, including the cost of diluent used in blending, are recognized when the product is sold.

(t) Purchased product and storage

Purchased product and storage costs include the cost of crude oil products purchased from third parties and associated transportation and storage costs.

(u) Net finance expense

Net finance expense is comprised of interest expense, net of interest income, debt extinguishment expense, accretion of the discount on provisions, and gains and losses on derivative financial instruments.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time required to complete and prepare the assets for their intended use. All other borrowing costs are recognized in finance expense using the effective interest method.

(v) 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, RSUs and PSUs granted to directors, officers, employees and consultants.

(w) New accounting standards

The Corporation has adopted the following revised standards effective January 1, 2017:

IAS 7, Statement of Cash Flows, has been amended by the IASB as part of its disclosure initiative to require additional disclosure for changes in liabilities arising from financing activities. This includes changes arising from cash flows and non-cash changes. Additional disclosures for changes in liabilities arising from financing activities have been included in Note 25. As allowed by IAS 7, comparative information has not been presented.

IAS 12, Income Taxes, has been amended to clarify the recognition of deferred tax assets relating to unrealized losses. The adoption of this revision did not have an impact on the Corporation's consolidated financial statements.

(x) 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 accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, but disclosure requirements are enhanced. 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. The Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements and is in the process of planning and identifying leases that are within the scope of the standard. The Corporation anticipates there will be a material impact on the consolidated financial statements and additional new disclosures.

ii. IFRS 9 Financial Instruments

In July 2014, the IASB issued IFRS 9 Financial Instruments, which is intended to replace 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 aligns with risk management activities. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The adoption of these changes will not have a material impact on the Corporation's consolidated financial statements.

A new 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 Corporation is currently assessing and evaluating the impact of the new amendment. IFRS 9 will be adopted by the Corporation on January 1, 2018, as required by the standard, on a modified retrospective basis.

iii. IFRS 15 Revenue From Contracts With Customers

In May 2014, the IASB issued IFRS 15 Revenue From Contracts With Customers, which will replace 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 new standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The Corporation will be adopting IFRS 15 retrospectively on January 1, 2018. The Corporation has substantially completed its assessment and evaluation of the underlying terms of its revenue contracts with customers and has determined that adoption of the standard will not have a material impact on the Corporation's consolidated financial statements. The Corporation anticipates there will be additional enhanced disclosures.

iv. IFRS 2 Share-based Payment

In June 2016, the IASB issued amendments to IFRS 2 Share-based Payment, relating to classification and measurement of particular share-based payment transactions. The amendments are effective for periods beginning on or after January 1, 2018, and will be applied prospectively as required by the standard. The Corporation anticipates that the adoption of these amendments will not have a material impact on the Corporation's consolidated financial statements.

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) Joint control

Judgment is required to determine whether an interest the Corporation holds in a joint arrangement should be classified as a joint operation or joint venture. The determination includes an assessment as to whether the Corporation has the rights to the assets and obligations for the liabilities of the arrangement or the rights to the net assets.

(e) 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.

(f) 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.

(g) 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.

(h) 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.

(i) 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.

5. TRADE RECEIVABLES AND OTHER

As at December 31		2017		2016
Trade receivables	$	266,789	$	219,054
Deposits and advances		13,189		13,571
Current portion of deferred financing costs		8,653		4,364
Current portion of interest rate swap		473		-
	$	289,104	$	236,989

6. INVENTORIES

As at December 31		2017		2016
Bitumen blend	$	64,077	$	46,571
Diluent		19,576		17,859
Materials and supplies		2,197		1,964
	$	85,850	$	66,394

During the year ended December 31, 2017, a total of $0.9 billion (2016 - $0.8 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, 2015	$	7,768,244	$	1,605,547	$	51,076	$	9,424,867
Additions		115,832		4,544		4,907		125,283
Dispositions		(3,641)		-		-		(3,641)
Change in decommissioning liabilities		(2,426)		27		-		(2,399)
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**
Accumulated depletion and depreciation								
Balance as at December 31, 2015	$	1,310,669	$	80,340	$	22,098	$	1,413,107
Depletion and depreciation		459,681		30,493		5,036		495,210
Dispositions		(3,641)		-		-		(3,641)
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**
Carrying amounts								
Balance as at December 31, 2016	$	6,111,300	$	1,499,285	$	28,849	$	7,639,434
Balance as at December 31, 2017	**$**	**6,113,842**	**$**	**1,477,207**	**$**	**43,350**	**$**	**7,634,399**

As at December 31, 2017, property, plant and equipment was assessed for impairment and no impairment has been recognized. Included in the cost of property, plant and equipment is $459.7 million of assets under construction (December 31, 2016 - $547.9 million).

8. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2015	$	546,421
Additions		2,265
Exploration expense		(1,248)
Change in decommissioning liabilities		314
Balance as at December 31, 2016	$	547,752
Additions		1,569
Change in decommissioning liabilities		(493)
Balance as at December 31, 2017	**$**	**548,828**

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, 2017, these assets were assessed for impairment within the aggregation of all of the Corporation's CGUs and no impairment has been recognized on exploration and evaluation assets.

9. INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2015	$	96,278
Additions		16,643
Balance as at December 31, 2016	$	112,921
Additions		534
Balance as at December 31, 2017	**$**	**113,455**

Accumulated depreciation		
Balance as at December 31, 2015	$	12,136
Impairment		80,072
Depreciation		4,602
Balance as at December 31, 2016	$	96,810
Depreciation		3,608
Balance as at December 31, 2017	**$**	**100,418**

Carrying amounts		
Balance as at December 31, 2016	$	16,111
Balance as at December 31, 2017	**$**	**13,037**

As at December 31, 2017, intangible assets consist of $13.0 million invested in software that is not an integral component of the related computer hardware (December 31, 2016 – $16.1 million). No impairment has been recognized on these assets for the year ended December 31, 2017.

At December 31, 2016, the Corporation evaluated its investment in the right to participate in the Northern Gateway pipeline for impairment in relation to the December 2016 directive from the Government of Canada to the National Energy Board to dismiss the project application. As a result, the Corporation fully impaired its investment and recognized a fourth quarter 2016 impairment charge of $80.1 million.

10. OTHER ASSETS

As at December 31	2017	2016
Long-term pipeline linefill[a]	**$ 122,657**	$ 129,733
Deferred financing costs[b]	**24,134**	12,001
Interest rate swap[c]	**8,067**	-
	154,858	141,734
Less current portion	**(9,126)**	(4,364)
	$ 145,732	$ 137,370

(a) Long-term pipeline linefill on third party owned pipelines is classified as a long-term asset as these transportation contracts extend beyond the year 2024. As at December 31, 2017, no impairment has been recognized on these assets.

(b) During the year ended December 31, 2017, the Corporation recognized deferred financing costs on modifications to its revolving credit facility and guaranteed letter of credit facility of $17.5 million and $2.9 million, respectively. These costs are being amortized as a component of net finance expense over the respective terms of the credit facilities (Note 12).

(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% (Note 27(c)). This interest rate swap contract commenced September 29, 2017 and expires on December 31, 2020. 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 interest rate swap is classified as a non-current derivative financial asset and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31	2017	2016
Accrued and other liabilities	**$ 333,988**	$ 217,424
Interest payable	**77,625**	71,945
Trade payables	**2,292**	2,971
	$ 413,905	$ 292,340

12. LONG-TERM DEBT

As at December 31	2017	2016
Senior secured term loan (December 31, 2017 - US$1.226 billion; due 2023; December 31, 2016 - US$1.236 billion)[a]	**$ 1,534,378**	$ 1,658,906
6.5% senior secured second lien notes (US$750.0 million; due 2025)[b]	**938,850**	-
6.5% senior unsecured notes (US$750.0 million; due 2021)[c]	**-**	1,007,025
6.375% senior unsecured notes (US$800.0 million; due 2023)[d]	**1,001,440**	1,074,160
7.0% senior unsecured notes (US$1.0 billion; due 2024)[e]	**1,251,800**	1,342,700
	4,726,468	5,082,791
Less unamortized financial derivative liability discount	**(4,242)**	(11,143)
Less unamortized deferred debt discount and debt issue costs[a][b]	**(38,499)**	(22,766)
Debt redemption premium[c]	**-**	21,812
	4,683,727	5,070,694
Less current portion of senior secured term loan	**(15,460)**	(17,455)
	$ 4,668,267	$ 5,053,239

	2018	2019	2020	2021	2022	Thereafter	Total
Required debt principal repayments	**$15,460**	**$15,460**	**$15,460**	**$15,460**	**$15,460**	**$4,649,168**	**$4,726,468**

The U.S. dollar denominated debt was translated into Canadian dollars at the year-end exchange rate of US$1 = C$1.2518 (December 31, 2016 – US$1 = C$1.3427).

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 to be 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, 2017, 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, 2017, letters of credit of US$258.4 million were issued and outstanding 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 February 8, 2018, the Corporation announced that it had entered into an agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of the Corporation's senior secured term loan. The expected repayment of debt reduces the estimated amortization period of the unamortized debt discount and debt issue costs, and the unamortized financial derivative liability discount. The change in estimate is 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 is 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 (Note 32).

As at December 31, 2017, the senior secured credit facilities are comprised of a US$1.226 billion 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 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 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.

(c) On March 15, 2017, the Corporation redeemed the previously outstanding US$750 million aggregate principal amount of 6.5% senior unsecured notes due 2021, utilizing the proceeds received from the issuance of the US$750 million, 6.5% senior secured second lien notes, which were held in escrow subject to the redemption. The 2.166% debt redemption premium of $21.8 million and associated remaining unamortized deferred debt issue costs of $7.0 million were recognized as debt extinguishment expense in the fourth quarter of 2016.

(d) 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.

(e) 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.

13. PROVISIONS AND OTHER LIABILITIES

As at December 31	2017	2016
Decommissioning provision[(a)]	$ 102,530	$ 133,924
Onerous contracts provision[(b)]	92,157	100,159
Derivative financial liabilities[(c)]	6,028	3,714
Deferred lease inducements and other[(d)]	32,243	3,304
Provisions and other liabilities	232,958	241,101
Less current portion	(27,446)	(23,063)
Non-current portion	$ 205,512	$ 218,038

(a) 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	2017	2016
Balance, beginning of year	**$ 133,924**	$ 130,381
Changes in estimated future cash flows	**(351)**	(91)
Changes in discount rates	**(19,602)**	4,436
Changes in estimated settlement dates	**(35,963)**	(10,553)
Liabilities incurred	**19,902**	4,123
Liabilities settled	**(2,403)**	(1,290)
Accretion	**7,023**	6,918
Balance, end of year	**102,530**	133,924
Less current portion	**(6,386)**	(3,097)
Non-current portion	**$ 96,144**	$ 130,827

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 $859.1 million (December 31, 2016 - $825.1 million). The Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 9.5% (December 31, 2016 – 8.2%) and an inflation rate of 2.10% (December 31, 2016 – 2.10%).

As at December 31, 2017, a 1% increase in the credit-adjusted risk-free rate would result in a $12.1 million decrease in the present value of the decommissioning provision. The decommissioning provision is estimated to be settled in periods up to the year 2067 (December 31, 2016 – periods up to the year 2066).

(b) Onerous contracts provision:

As at December 31	2017	2016
Balance, beginning of year	**$ 100,159**	$ 58,178
Changes in estimated future cash flows	**13,337**	40,499
Changes in discount rates	**(2,507)**	(1,478)
Liabilities incurred	**-**	8,845
Liabilities settled	**(19,569)**	(6,116)
Accretion	**737**	231
Balance, end of year	**92,157**	100,159
Less current portion	**(19,047)**	(18,930)
Non-current portion	**$ 73,110**	$ 81,229

As at December 31, 2017, the Corporation has recognized a provision of $92.2 million related to onerous operating lease contracts (December 31, 2016 – $100.2 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 operating lease contracts and estimated recoveries. The total undiscounted amount of the estimated future cash flows to settle the onerous contracts obligations is $102.1 million (December 31, 2016 - $106.2 million). These cash flows have been discounted using a risk-free discount rate of 1.8% (December 31, 2016 – 1.3%). 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, 2016 – periods up to the year 2031).

(c) Derivative financial liabilities:

As at December 31		2017		2016
1% interest rate floor	**$**	**6,028**	$	3,714
Less current portion		**(90)**		(517)
Non-current portion	**$**	**5,938**	$	3,197

The interest rate floor on the senior secured term loan has been recognized as an embedded derivative, as the floor rate exceeded the market rate of interest at the time that the debt was incurred.

(d) Deferred lease inducements and other:

During the year ended December 31, 2017, the Corporation recognized a $21.5 million tenant improvement allowance related to its corporate office lease. The allowance will be amortized and treated as a reduction to general and administrative expenses over the 15-year term of the lease. In addition, the Corporation recognized a $9.4 million long-term liability to be settled in installments over the next four years.

14. INCOME TAXES

The income tax provision differs from results which would be obtained if the Corporation applied the combined federal and provincial statutory rate of 27% (2016 – 27%) to earnings or loss before income taxes as follows:

For the years ended December 31		2017		2016
Expected income tax expense (recovery)	**$**	**29,640**	$	(171,780)
Add (deduct) the tax effect of:				
Stock-based compensation		**5,144**		9,069
Non-taxable loss (gain) on foreign exchange		**(46,390)**		(21,232)
Taxable capital loss (gain) not recognized		**(46,390)**		(21,232)
Tax benefit of vested RSUs		**(1,166)**		(2,133)
Other		**2,965**		(186)
Income tax expense (recovery)	**$**	**(56,197)**	$	(207,494)
Current income tax expense (recovery)	**$**	**(67)**	$	919
Deferred income tax expense (recovery)		**(56,130)**		(208,413)
Income tax expense (recovery)	**$**	**(56,197)**	$	(207,494)

During the year ended December 31, 2017, the Corporation recognized a current income tax recovery of $0.1 million (year ended December 31, 2016 - $0.9 million income tax expense). The recovery is comprised of $0.8 million relating to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures, partially offset by an expense of $0.7 million relating to the United States income tax associated with its operations in the United States. The 2016 expense was related to the United States income tax associated with its operations in the United States.

The Corporation has recognized a deferred tax asset of $182.9 million (December 31, 2016 – $120.9 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	2017	2016
Deferred tax assets:		
Deferred tax assets to be recovered after more than 12 months	**$ 1,381,512**	$ 1,255,527
Deferred tax assets to be recovered within 12 months	**29,856**	17,627
	1,411,368	1,273,154
Deferred tax liabilities:		
Deferred tax liabilities to be recovered after more than 12 months	**(1,228,497)**	(1,151,317)
Deferred tax liabilities to be recovered within 12 months	**-**	(893)
	(1,228,497)	(1,152,210)
Deferred tax assets (liabilities), net	**$ 182,871**	$ 120,944

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

	2017	2016
Balance as at January 1	**$ 120,944**	$ (87,469)
Credited (charged) to earnings	**56,130**	208,413
Credited (charged) to other comprehensive income	**(9)**	-
Credited (charged) to equity	**5,806**	-
Balance as at December 31	**$ 182,871**	$ 120,944

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

Deferred tax assets	Tax losses	Derivative financial liabilities	Provisions	Other	Total
Balance as at December 31, 2015	$ 973,665	$ 4,380	$ 2,267	$ 30,141	$ 1,010,453
Credited (charged) to earnings	234,390	4,807	1,520	21,984	262,701
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**

Deferred tax liabilities	Property, plant and equipment	Other	Total
Balance as at December 31, 2015	$ (1,087,428)	$ (10,494)	$ (1,097,922)
Credited (charged) to earnings	(54,996)	708	(54,288)
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)**

As at December 31, 2017, the Corporation had approximately $8.4 billion in available tax pools (December 31, 2016 - $8.0 billion). Included in the tax pools are $4.9 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 $3.5 billion after 2030). In addition, as at December 31, 2017, the Corporation had an additional $6.0 million (December 31, 2016 - $0.2 billion) of capital investment in incomplete projects which will serve to increase available tax pools upon completion of the projects. As at December 31, 2017, the Corporation had not recognized the tax benefit related to $0.4 billion of realized and unrealized taxable capital foreign exchange losses (December 31, 2016 - $0.6 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	**2017**		**2016**	
	Number of shares	**Amount**	**Number of shares**	**Amount**
Balance, beginning of year	**226,467,107**	**$ 4,878,607**	224,996,989	$ 4,836,800
Shares issued	**66,815,000**	**517,816**	-	-
Share issue costs net of tax	**-**	**(15,698)**	-	-
Issued upon vesting and release of RSUs and PSUs	**821,836**	**23,253**	1,470,118	41,807
Balance, end of year	**294,103,943**	**$ 5,403,978**	226,467,107	$ 4,878,607

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 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.

RSUs and PSUs outstanding:

Year ended December 31	**2017**	**2016**
Outstanding, beginning of year	**6,013,010**	-
Granted	**1,454,659**	6,132,701
Vested and released	**(1,467,027)**	-
Forfeited	**(690,569)**	(119,691)
Outstanding, end of year	**5,310,073**	6,013,010

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, 2017, there were 284,871 DSUs outstanding (December 31, 2016 – 163,954 DSUs outstanding).

As at December 31, 2017, the Corporation has recognized a liability of $14.3 million relating to the fair value of RSUs, PSUs and DSUs (December 31, 2016 – $19.2 million).

(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	2017			2016		
	Stock options		Weighted average exercise price	Stock options		Weighted average exercise price
Outstanding, beginning of year	**9,281,186**	**$**	**27.45**	9,925,313	$	29.94
Granted	**1,211,880**		**4.57**	1,214,300		6.52
Forfeited	**(927,256)**		**27.78**	(851,422)		30.73
Expired	**(669,807)**		**33.81**	(1,007,005)		24.00
Outstanding, end of year	**8,896,003**	**$**	**23.81**	9,281,186	$	27.45

As at December 31, 2017								
	Outstanding				Vested			
Range of exercise prices	Options		Weighted average exercise price	Weighted average remaining life (in years)	Options		Weighted average exercise price	Weighted average remaining life (in years)
$4.53 - $10.00	2,308,480	$	5.49	6.00	365,522	$	6.52	5.49
$10.01 - $20.00	2,364,946		18.52	4.45	1,581,898		18.52	4.45
$20.01 - $30.00	40,401		22.83	3.76	31,582		23.32	3.65
$30.01 - $40.00	3,624,122		34.83	2.54	3,624,122		34.83	2.54
$40.01 - $51.43	558,054		50.50	0.46	558,054		50.50	0.46
	8,896,003	**$**	**23.81**	**3.82**	**6,161,178**	**$**	**30.32**	**3.02**

The fair value of each option granted during the years ended December 31, 2017 and 2016 was estimated on the date of the grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2017	2016
Risk-free rate	**1.14%**	0.57%
Expected lives	**5 years**	5 years
Volatility[i]	**59%**	53%
Annual dividend per share	**$ nil**	$ nil
Fair value of options granted	**$ 2.11**	$ 3.20

(i) Expected volatility is determined by the average price volatility of the 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 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.

RSUs and PSUs outstanding:

Year ended December 31	2017	2016
Outstanding, beginning of year	**1,655,606**	3,280,112
Granted	**5,756,580**	-
Vested and released	**(822,821)**	(1,470,118)
Forfeited	**(282,137)**	(154,388)
Outstanding, end of year	**6,307,228**	1,655,606

(c) Stock-based compensation

Year ended December 31	2017	2016
Cash-settled expense[i]	**$ 3,476**	$ 16,354
Equity-settled expense	**19,052**	33,588
Stock-based compensation	**$ 22,528**	$ 49,942

(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. Fluctuations in the fair value are recognized during the period in which they occur

17. PETROLEUM REVENUE, NET OF ROYALTIES

Year ended December 31	2017	2016
Petroleum revenue[a]		
Proprietary	**$ 2,168,602**	$ 1,626,025
Third-party[b]	**253,486**	205,790
Petroleum revenue	**2,422,088**	1,831,815
Royalties	**(22,578)**	(8,581)
Petroleum revenue, net of royalties	**$ 2,399,510**	$ 1,823,234

(a) The Corporation had two major customers each with revenue in excess of 10% of total petroleum revenue. Sales to major customers totaled $0.9 billion for the year ended December 31, 2017 (year ended December 31, 2016 - $1.1 billion).

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

18. OTHER REVENUE

Year ended December 31		2017		2016
Power revenue	**$**	**22,209**	$	18,868
Transportation revenue		**12,801**		19,791
Insurance proceeds		**183**		4,391
Other revenue	**$**	**35,193**	$	43,050

19. DILUENT AND TRANSPORTATION

Year ended December 31		2017		2016
Diluent expense	**$**	**944,134**	$	808,030
Transportation expense		**214,280**		209,864
Diluent and transportation	**$**	**1,158,414**	$	1,017,894

20. FOREIGN EXCHANGE LOSS (GAIN), NET

Year ended December 31		2017		2016
Unrealized foreign exchange loss (gain) on:				
Long-term debt	**$**	**(343,633)**	$	(157,272)
Other		**5,489**		9,119
Unrealized net loss (gain) on foreign exchange		**(338,144)**		(148,153)
Realized loss (gain) on foreign exchange		**(4,403)**		(3,242)
Foreign exchange loss (gain), net	**$**	**(342,547)**	$	(151,395)
C$ equivalent of 1 US$				
Beginning of year		**1.3427**		1.3840
End of year		**1.2518**		1.3427

21. NET FINANCE EXPENSE

Year ended December 31		2017		2016
Total interest expense	**$**	**341,594**	$	328,335
Total interest income		**(3,924)**		(1,047)
Net interest expense		**337,670**		327,288
Debt extinguishment expense[a]		**30,801**		28,845
Accretion on provisions		**7,760**		7,150
Unrealized gain on derivative financial liabilities		**(16,179)**		(12,508)
Realized loss on interest rate swaps		**1,028**		4,548
Net finance expense	**$**	**361,080**	$	355,323

(a) On February 8, 2018, the Corporation announced that it had entered into an agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of the Corporation's senior secured term loan. The expected repayment of debt reduces the estimated amortization period of the unamortized debt discount and debt issue costs, and the unamortized financial derivative liability discount. The change in estimate is 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 is 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 (Note 32).

At December 31, 2016, the Corporation recognized $28.8 million of debt extinguishment expense associated with the planned redemption of the 6.5% senior unsecured notes on March 15, 2017, under the comprehensive refinancing plan completed on January 27, 2017 (Note 12(c)). The debt extinguishment expense is comprised of a redemption premium of $21.8 million and the associated remaining unamortized deferred debt issue costs of $7.0 million.

22. OTHER EXPENSES

Year ended December 31		**2017**		**2016**
Contract cancellation	**$**	**18,765**	$	-
Onerous contracts		**10,830**		47,866
Severance and other		**5,131**		16,156
Other expenses	**$**	**34,726**	$	64,022

During the year ended December 31, 2017, the Corporation recognized an $18.8 million contract cancellation expense relating to the termination of a long-term transportation contract.

23. WAGES AND EMPLOYEE BENEFITS EXPENSE

Year ended December 31		**2017**		**2016**
Operating expense:				
Salaries and wages(i)	**$**	**48,574**	$	48,958
Short-term employee benefits		**5,454**		5,928
General and administrative expense:				
Salaries and wages(i)		**58,806**		63,489
Short-term employee benefits		**9,047**		11,400
	$	**121,881**	$	129,775

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

24. TRANSACTIONS WITH RELATED PARTIES

During the years ended December 31, 2017 and December 31, 2016, related party transactions include the compensation of key management personnel. The Corporation considers directors and officers of the Corporation as key management personnel.

Year ended December 31		**2017**		**2016**
Salaries and short-term employee benefits	**$**	**7,385**	$	9,117
Share-based compensation		**9,578**		12,006
Termination benefits		**64**		1,617
	$	**17,027**	$	22,740

25. SUPPLEMENTAL CASH FLOW DISCLOSURES

Year ended December 31		2017		2016
Cash provided by (used in):				
Trade receivables and other	**$**	**(52,074)**	$	(83,601)
Inventories		**(19,591)**		(13,524)
Accounts payable and accrued liabilities		**123,380**		74,667
	$	**51,715**	$	(22,458)
Changes in non-cash working capital relating to:				
Operating	**$**	**(24,517)**	$	(25,061)
Investing		**76,232**		2,603
	$	**51,715**	$	(22,458)
Cash and cash equivalents:[(a)]				
Cash	**$**	**276,023**	$	156,230
Cash equivalents		**187,508**		-
	$	**463,531**	$	156,230
Cash interest paid	**$**	**294,743**	$	286,983
Cash interest received	**$**	**3,660**	$	1,046

(a) As at December 31, 2017, C$201.0 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars. (December 31, 2016 - C$102.8 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$1.2518 (December 31, 2016 - US$1 = C$1.3427).

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

		Other assets		Long-term debt
Balance as at December 31, 2016[(i)]	$	12,001	$	5,070,694
Cash changes:				
Debt refinancing costs[(a)]		20,447		(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[(b)]		-		30,801
Amortization of financial derivative liability discount		-		3,520
Amortization of deferred debt discount and debt issue costs		(8,314)		7,391
Balance as at December 31, 2017[(i)]	**$**	**24,134**	**$**	**4,683,727**

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

(a) During the year ended December 31, 2017, debt refinancing costs of $82.4 million were paid, including $61.9 million for the refinancing and maturity extension of the Corporation's US$1.2 billion term loan and replacement of the Corporation's US$750 million senior unsecured notes with US$750 million senior secured second lien notes (Note 12). Refinancing costs related to amendments and extensions to the revolving credit facility and to the guaranteed letter of credit facility of $17.5 million and $2.9 million respectively, have been recognized as a component of Other Assets (Note 10).

(b) On February 8, 2018, the Corporation announced that it had entered into an agreement for the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of the Corporation's senior secured term loan. The expected repayment of debt reduces the estimated amortization period of the unamortized debt discount and debt issue costs, and the unamortized financial derivative liability discount. The change in estimate is 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 (Note 32).

26. NET EARNINGS (LOSS) PER COMMON SHARE

Year ended December 31		**2017**		**2016**
Net earnings (loss)	**$**	**165,976**	$	(428,726)
Weighted average common shares outstanding[(a)]		**289,142,338**		225,982,724
Dilutive effect of stock options, RSUs and PSUs[(b)]		**116,583**		-
Weighted average common shares outstanding - diluted		**289,258,921**		225,982,724
Net earnings (loss) per share, basic	**$**	**0.57**	$	(1.90)
Net earnings (loss) per share, diluted	**$**	**0.57**	$	(1.90)

(a) Weighted average common shares outstanding for the year ended December 31, 2017 includes 139,863 PSUs not yet released (year ended December 31, 2016 – 184,425 PSUs).

(b) For the year ended December 31, 2016, 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, 2016, the dilutive effect of stock options, RSUs and PSUs would have been 122,500 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, derivative financial liabilities included within provisions and other liabilities, long-term debt and debt redemption premium liability included within long-term debt. As at December 31, 2017, commodity risk management contracts, the interest rate swap and derivative financial liabilities were classified as held-for-trading financial instruments; cash and cash equivalents and trade receivables and other were classified as loans and receivables; and accounts payable and accrued liabilities were classified as other financial liabilities. Long-term debt was 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 measurement of long-term debt, derivative financial liabilities, derivative financial assets, commodity risk management contracts and debt redemption premium liability:

As at December 31, 2017		Carrying amount	Fair value measurements using 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 (Note 13)	$	6,028	-	$	6,028	-
Commodity risk management contracts	$	68,649	-	$	68,649	-

As at December 31, 2016		Carrying amount	Fair value measurements using Level 1		Level 2	Level 3
Recurring measurements:						
Financial liabilities						
Long-term debt(i) (Note 12)	$	5,082,791	-	$	4,768,344	-
Derivative financial liabilities (Note 13)	$	3,714	-	$	3,714	-
Commodity risk management contracts	$	30,313	-	$	30,313	-
Debt redemption premium (Note 12)	$	21,812	-	$	21,812	-

(i) Includes the current and long-term portions.

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

As at December 31, 2017, 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 and derivative financial assets and 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.

As at December 31, 2017, the Corporation did not have any financial instruments measured at Level 3 fair value. 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 has the following financial commodity risk management contracts relating to crude oil sales outstanding as at December 31, 2017:

As at December 31, 2017	Volumes (bbls/d)(i)	Term	Average Price (US$/bbl)(i)
Fixed Price:			
WTI(ii) Fixed Price	30,700	Jan 1, 2018 – Jun 30, 2018	$52.89
WTI Fixed Price	22,500	Jul 1, 2018 – Dec 31, 2018	$52.72
WTI:WCS(iii) Fixed Differential	48,700	Jan 1, 2018 – Jun 30, 2018	$(14.43)
WTI:WCS Fixed Differential	32,000	Jul 1, 2018 – Dec 31, 2018	$(14.68)
Collars:			
WTI Collars	41,500	Jan 1, 2018 – Jun 30, 2018	$46.71 – $54.97
WTI Collars	32,500	Jul 1, 2018 – Dec 31, 2018	$46.64 – $54.52

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

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

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

The Corporation has entered into the following financial commodity risk management contracts relating to crude oil sales subsequent to December 31, 2017. As a result, these contracts are not reflected in the Corporation's consolidated financial statements:

Subsequent to December 31, 2017	Volumes (bbls/d)(i)	Term	Average Price (US$/bbl)(i)
Fixed Price:			
WTI Fixed Price	3,000	Apr 1, 2018 – Jun 30, 2018	$63.82
WTI Fixed Price	11,500	Jul 1, 2018 – Dec 31, 2018	$60.20

The Corporation has entered into the following financial commodity risk management contracts relating to condensate purchases subsequent to December 31, 2017. As a result, these contracts are not reflected in the Corporation's consolidated financial statements:

Subsequent to December 31, 2017	Volumes (bbls/d)(i)	Term	Average % of WTI(i)
Mont Belvieu fixed % of WTI	1,000	Apr 1, 2018 – Jun 30, 2018	92.3%
Mont Belvieu fixed % of WTI	500	Jul 1, 2018 – Sep 30, 2018	93.5%

(i) 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.

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, 2017			December 31, 2016		
	Asset	Liability	Net	Asset	Liability	Net
Gross amount	**$ -**	**$ (184,175)**	**$ (184,175)**	$ -	$ (165,740)	$ (165,740)
Amount offset	**-**	**115,526**	**115,526**	-	135,427	135,427
Net amount	**$ -**	**$ (68,649)**	**$ (68,649)**	$ -	$ (30,313)	$ (30,313)

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	2017	2016
Fair value of contracts, beginning of year	$ (30,313)	$ -
Fair value of contracts realized	11,273	(2,359)
Change in fair value of contracts	(49,609)	(27,954)
Fair value of contracts, end of year	$ (68,649)	$ (30,313)

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

For the year ended December 31	2017	2016
Realized loss (gain) on commodity risk management	$ 11,273	$ (2,359)
Unrealized loss (gain) on commodity risk management	38,336	30,313
Commodity risk management loss (gain)	$ 49,609	$ 27,954

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, 2017:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$5.00 per bbl applied to WTI contracts	$ (145,090)	$ 140,206
Crude oil differential price[(i)]	± US$1.00 per bbl applied to WCS differential contracts	$ 18,414	$ (18,414)

(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.

(c) 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. The Corporation has 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. As at December 31, 2017, the Corporation has recognized an $8.1 million derivative financial asset related to this interest rate swap.

Amount	Effective date	Remaining term	Fixed rate	Floating rate
US$650 million	September 29, 2017	Oct 1, 2017 – Dec 31, 2020	5.319%(i)	3 month LIBOR (ii) + 3.5% credit spread

(i) Comprised of the fixed rate on the interest rate swap contract of 1.819% plus 3.5% credit spread

(ii) London Interbank Offered Rate

As at December 31, 2017, a 100 basis points increase in the LIBOR on the floating rate debt would have resulted in a $14.1 million decrease in net earnings before income taxes (December 31, 2016 - $6.5 million). As at December 31, 2017, a 100 basis points decrease in LIBOR would have resulted in a $2.6 million increase in net earnings before income taxes (December 31, 2016 - $nil).

(d) Foreign currency risk:

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, 2017, 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$37.8 million (December 31, 2016 - C$37.9 million).

(e) Credit risk:

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. This 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 counterparties' 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. All transactions with financial institutions are made with those that have investment grade credit ratings. As at December 31, 2017, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $280.0 million. There were no significant trade receivables which were greater than 90 days as at December 31, 2017.

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, 2017 was $463.5 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 $463.5 million.

(f) Liquidity risk:

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, 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	5,938	-	-
Accounts payable and accrued liabilities	336,280	336,280	-	-	-
	$ 6,907,139	**$ 712,525**	**$ 618,540**	**$ 609,384**	**$ 4,966,690**

As at December 31, 2016	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long-term debt	$ 5,082,791	$ 17,455	$ 34,910	$ 2,613,566	$ 2,416,860
Interest on long-term debt	1,569,849	289,940	577,917	416,333	285,659
Debt redemption premium	21,812	21,812	-	-	-
Commodity risk management contracts	30,313	30,313	-	-	-
Derivative financial liabilities	3,714	517	3,197	-	-
Accounts payable and accrued liabilities	220,395	220,395	-	-	-
	$ 6,928,874	**$ 580,432**	**$ 616,024**	**$ 3,029,899**	**$ 2,702,519**

28. GEOGRAPHICAL DISCLOSURE

As at December 31, 2017, the Corporation had non-current assets related to operations in the United States of $101.7 million (December 31, 2016 - $109.2 million). For the year ended December 31, 2017, petroleum revenue related to operations in the United States was $1.1 billion (year ended December 31, 2016 - $664.2 million).

29. JOINT OPERATIONS

The Corporation transports its bitumen blend volumes and diluent purchases on pipelines that are operated by Access Pipeline. The Corporation has an undivided 50% interest in this jointly controlled entity and presents its proportionate share of the assets, liabilities, revenues and expenses of the joint operation on a line-by-line basis in the consolidated financial statements. As at December 31, 2017, the Corporation's proportionate interest in the joint operation's working capital balances was $2.4 million (December 31, 2016 - $2.9 million) and its interest in related pipeline assets, recorded in property, plant and equipment, was $1.05 billion (December 31, 2016 - $1.06 billion).

Operating commitments of $12.2 million related to the joint operation are included within "Commitments" presented within Note 30(a).

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, 2017, which exclude any impact related to transactions that occurred subsequent to December 31, 2017 as described in Note 32:

	2018	2019	2020	2021	2022	Thereafter	Total
Transportation and storage(i)	$ 169,248	$ 182,850	$ 227,393	$ 283,457	$ 284,128	$ 2,248,252	$ 3,395,328
Office lease rentals(ii)	10,863	10,863	11,286	11,286	11,286	107,667	163,251
Diluent purchases	483,812	19,563	19,617	19,563	19,563	16,294	578,412
Other operating commitments	14,160	12,487	11,440	10,418	9,331	60,394	118,230
Capital commitments	14,843	-	-	-	-	-	14,843
Commitments	**$ 692,926**	**$ 225,763**	**$ 269,736**	**$ 324,724**	**$ 324,308**	**$ 2,432,607**	**$ 4,270,064**

(i) Includes transportation commitments of $1.2 billion that are awaiting regulatory approval and are not yet in service.

(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. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation continues to view this three year old claim, and the recent amendments, as without merit and will defend against all such claims.

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, 2017, the Corporation's capital resources included $313.0 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$258.4 million of letters of credit have been issued. Working capital is comprised of $463.5 million of cash and cash equivalents, offset by a non-cash working capital deficiency of $150.5 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.

32. SUBSEQUENT EVENTS

On February 7, 2018, the Corporation entered into an agreement with Wolf Midstream Inc. ("Wolf") for the sale of the Corporation's 50% interest in Access Pipeline and its 100% interest in the Stonefell Terminal for cash and other consideration of $1.61 billion ("the transaction"). The transaction was announced on February 8, 2018.

As part of the transaction, the Corporation and Wolf have entered into a Transportation Services Agreement dedicating the Corporation's Christina Lake production and condensate transport to 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 the Corporation's operational control and exclusive use of 100% of Stonefell Terminal's 900,000 barrel blend and condensate storage facility. The sale of the Stonefell Terminal and the Stonefell Lease Agreement will be accounted for as a sale and leaseback transaction that results in a finance lease.

The Corporation will receive $1.52 billion in cash at closing, and a credit of $90 million toward future expansions of Access Pipeline whereby the Corporation will not pay incremental tolls to fund such expansions. Upon closing, a portion of the net cash proceeds will be used to repay approximately C$1.225 billion of MEG's senior secured term loan.

As a result of the transaction announced on February 8, 2018, the Corporation determined that the expected repayment of debt results in a change in estimated life of certain amounts associated with the senior secured term loan. A debt extinguishment expense of $30.8 million was recorded at December 31, 2017, as an adjusting subsequent event under IAS 10, Events after the Reporting Period.

The transaction is expected to close in the first quarter of 2018, subject to regulatory approvals and customary closing conditions.

Subsequent to entering into the agreement, the Corporation entered into forward currency contracts to manage the foreign exchange risk on the Canadian dollar denominated proceeds from the sale of assets designated for U.S. dollar denominated long-term debt repayment.

DIRECTORS AND OFFICERS

BOARD OF DIRECTORS

Jeffrey J. McCaig [4]
Chairman
Alberta, Canada

William (Bill) McCaffrey [5]
Alberta, Canada

Boyd Anderson [1][4][7]
Alberta, Canada

Harvey Doerr [4][6]
British Columbia, Canada

Robert B. Hodgins [1][2][4]
Alberta, Canada

Timothy E. Hodgson [1][4]
Toronto, Ontario

Daniel S. Farb [4]
Massachusetts, U.S.A.

William R. (Bill) Klesse [4]
San Antonio, Texas

David B. Krieger [2][4]
New York, U.S.A.

James D. McFarland [2][3][4]
Alberta, Canada

Diana J. McQueen [2][3][4]
Alberta, Canada

CORPORATE OFFICERS

William (Bill) McCaffrey [5]
President, Chief Executive Officer and Director

Eric L. Toews
Chief Financial Officer

Don G. Moe [8]
Senior Vice President, Supply and Marketing

Richard F. Sendall
Senior Vice President,
Strategy and Government Relations

Chi-Tak Yee
Senior Vice President, Operations,
Resource and Technology Development

Grant Borbridge
Senior Vice President, Legal and General Counsel

John Nearing
Vice President,
Finance and Corporate Services

John M. Rogers
Vice President, Investor Relations
and External Communications

Chris Sloof
Vice President, Projects

Don Sutherland [9]
Vice President, Regulatory and
Community Relations

(1) Member of the Audit Committee. Mr. Hodgins is the Chair of the Audit Committee.
(2) Member of the Compensation Committee. Mr. McFarland is the Chair of the Compensation Committee.
(3) Member of the Governance and Nominating Committee. Ms. McQueen was appointed Chair of the Governance and Nominating Committee effective April 12, 2018.
(4) Independent director.
(5) Mr. McCaffrey is retiring from the position of President and Chief Executive Officer of the Corporation effective May 31, 2018 and is also not standing for re-election as a director in 2018.
(6) Mr. Doerr resigned as Chair and member of the Governance and Nominating Committee on April 12, 2018.
(7) Mr. Anderson is not standing for re-election as a director in 2018.
(8) Mr. Moe will cease to be Senior Vice President, Supply & Marketing of the Corporation on May 10, 2018.
(9) Mr. Sutherland has advised the Corporation that he will retire from the position of Vice President, Regulatory and Community Relations effective June 30, 2018.

INFORMATION FOR SHAREHOLDERS

MEG ENERGY CORP. SHARES ARE TRADED ON THE TORONTO STOCK EXCHANGE UNDER THE SYMBOL "MEG"

Transfer Agent
Computershare Investor Services
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Toronto, ON M5J 2Y1
Toll Free: (800) 564 6253
www.investorcentre.com/service

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GLJ Petroleum Consultants

Analyst and Investor Inquiries
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403-770-0446

Auditor
PricewaterhouseCoopers LLP

Annual Meeting of Shareholders
May 31, 2018
Bow Glacier Room
Centennial Place, West Tower
3rd Floor, 250 5th Street SW
Calgary, AB

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