MEG ENERGY

2015 ANNUAL REPORT

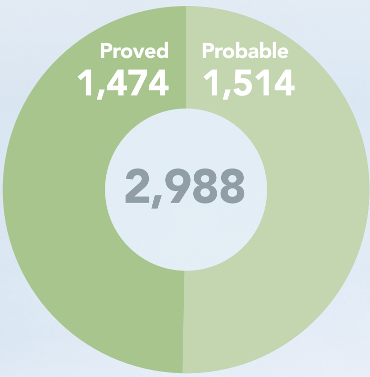
MEG Energy Corp.

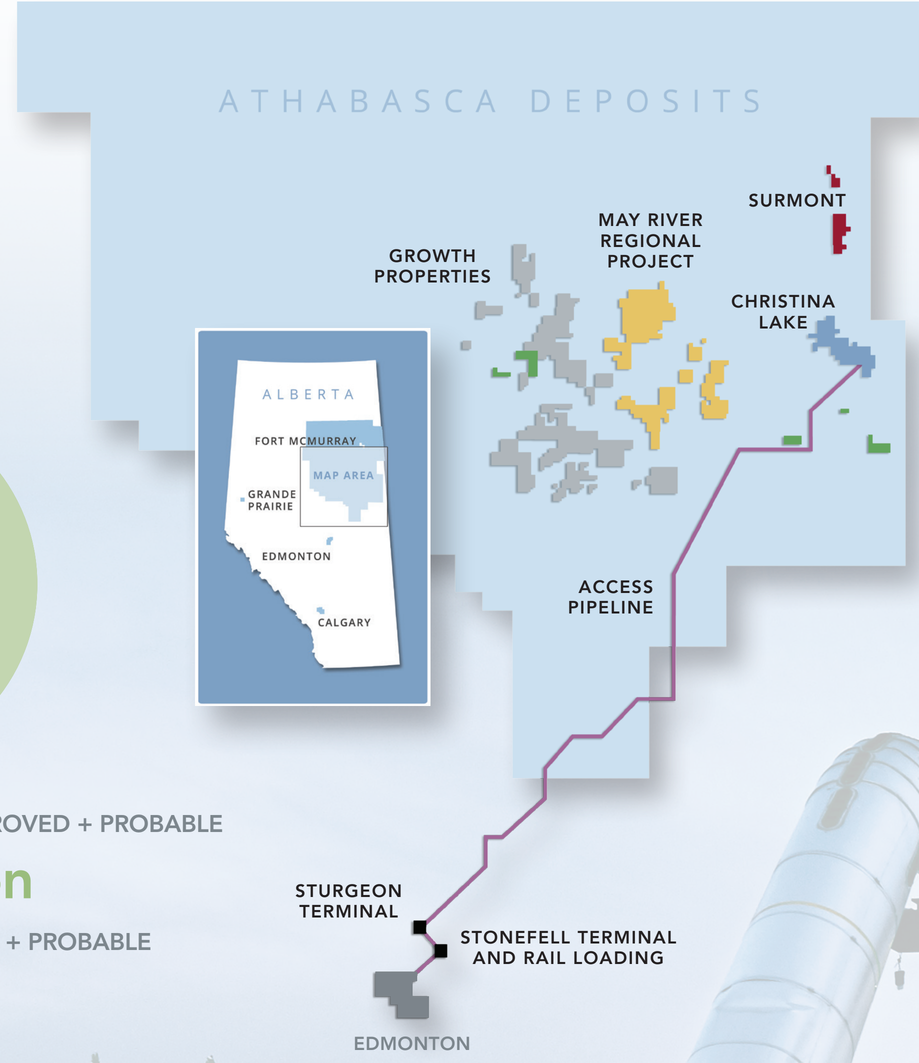
is a Canadian energy company focused on sustainable in situ development and production in the southern Athabasca oil sands region of Alberta.

Strategic. Innovative. Responsible. A Message to Our Shareholders

Significant Reserves

barrels in millions





CHRISTINA LAKE PV-10% PROVED + PROBABLE

$17.5 billion

SURMONT PV-10% PROVED + PROBABLE

$3.1 billion

Based on GLJ Reserve Report dated effective as of December 31, 2015.

Evaluated by GLJ

Exploration lands

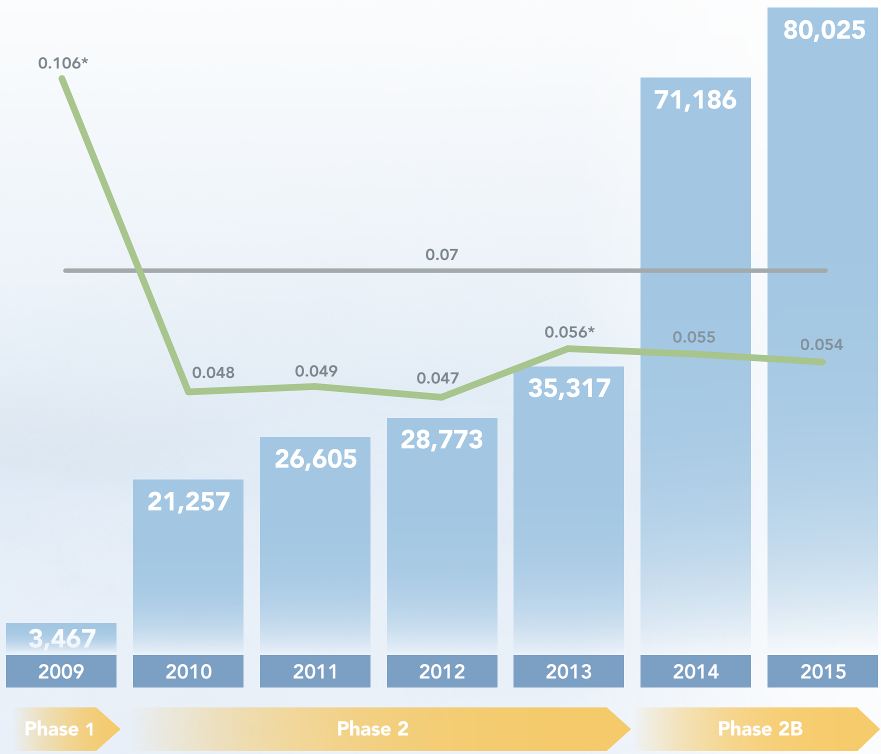
Strategic. Innovative. Responsible.

Production Growth

Bitumen Production (bpd)

MEG Net GHG Intensity** (t CO_2e/bbl)

Industry Average GHG Intensity (t CO_2e/bbl)



* Phase Start-Up - Higher steam requirements with low initial production

** Net GHG intensity includes the associated benefits of cogeneration.

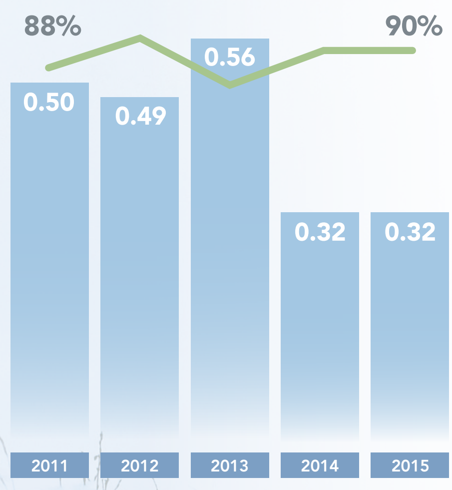
Source: Third-party verified MEG GHG data, Environment Canada Nationa l Inventory Report, CAPP Responsible Canadian Energy 2013 Progress Report Summary, industry average estimate.

Water Use Intensity

Water Use (barrels of water used to produce a barrel of bitumen)

Water Recycling Rate

All of MEG's water use is sourced from non-potable ground water that is not suitable for consumption or agricultural uses.



Operational and Financial Highlights

(Cdn$ millions, except as indicated)	2015	2014	2013	2012	2011
Bitumen production (barrels per day)	**80,025**	71,186	35,317	28,773	26,605
Bitumen sales (barrels per day)	**80,965**	67,243	33,715	28,845	26,587
Steam to oil ratio (SOR)	**2.5**	2.5	2.6	2.4	2.4
West Texas Intermediate (WTI) (US$/barrel)	**48.80**	93.00	97.96	94.21	95.12
West Texas Intermediate (WTI) (Cdn$/barrel)	**62.40**	102.74	100.86	94.14	94.10
Bitumen realization (Cdn$ per barrel)	**30.63**	62.67	49.28	46.93	58.74
Net operating costs (Cdn$ per barrel)	**9.39**	12.06	10.01	9.98	10.96
Non-energy operating costs (Cdn$ per barrel)	**6.54**	8.02	9.00	9.71	10.32
Cash operating netback[1] (Cdn$ per barrel)	**15.72**	44.87	35.87	34.18	43.15
Cash flow from operations[2]	**49.5**	791.5	253.4	212.5	304.6
Per share, diluted[3]	**0.22**	3.52	1.13	1.06	1.54
Operating earnings[2]	**(374.4)**	247.4	0.4	21.2	109.3
Per share, diluted[2]	**(1.67)**	1.10	–	0.11	0.55
Revenue	**1,925.9**	2,830.0	1,334.5	1,050.5	1,036.6
Net earnings (loss)[3]	**(1,169.7)**	(105.5)	(166.4)	52.6	63.8
Per share, diluted	**(5.21)**	(0.47)	(0.75)	0.26	0.32
Total cash capital investment	**257.2**	1,237.5	2,111.8	1,567.9	914.3
Cash and cash equivalents	**408.2**	656.1	1,179.1	1,474.8	1,495.1
Long-term debt	**5,190.4**	4,350.4	3,990.7	2,478.7	1,741.4

1 *Cash operating netbacks are calculated by deducting the related diluent, transportation, operating expenses and royalties from proprietary sales volumes and power revenues, on a per barrel basis.*

2 *Cash flow from operations, Operating earnings, and the related per share amounts do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS") and therefore may not be comparable to similar measures used by other companies. Please see the "ADVISORY" section of this report.*

3 *Includes unrealized foreign exchange gains/losses on translation of the U.S. dollar denominated debt.*

To Our Shareholders

MAY 2016

THERE'S NO QUESTION THAT 2015 REPRESENTED ONE OF THE MOST CHALLENGING YEARS OVER THE PAST DECADE FOR CANADA'S ENERGY INDUSTRY. MEG HAS WORKED HARD TO RISE TO THE CHALLENGES.

Our focus has been to continue to innovate and constantly improve with the goal of better positioning the company to be able to grow, even within the current low oil price environment.

Over the course of 2015 and into 2016, we realized record production levels, achieved record-low operating costs, and continued to increase our reach into high value markets. And, we refocused our future growth strategy toward incremental 'brownfield' investments that maximize existing assets – before launching new 'greenfield' projects – with a goal of minimizing growth capital and sustaining capital.

Starting with our original Christina Lake Phase 1 project, and continuing through Phases 2 and 2B, we have been on a constant journey of learning and innovation to drive low-capital and low-operating cost production growth, both of which continue to rank among the best in the oil sands industry.

Based on our RISER initiative, we have expanded from a combined design capacity of 60,000 barrels per day for Phases 1, 2 and 2B to producing more than 83,500 barrels per day at the end of 2015 – nearly 40 percent above our original base production volumes. We continue to use a balanced and systematic approach toward growing our business. Technology-driven efficiency gains that have been realized in our reservoirs have been matched with debottlenecking of our processing facilities to accommodate higher volumes.

Recent tests confirm that our facilities have a total oil treating capacity of more than 110,000 barrels per day. Reaching that level will require coordination between further optimization of our recovery processes – freeing up more steam for new wells – and brownfield modification to our central processing facilities. We also now believe that through smaller, more nimble, brownfield expansions, we will ultimately be able to achieve production of 120,000 barrels per day.

In the near term, a tight focus on cost management has delivered net operating costs of well under $10 per barrel in 2015, which is very competitive in the North American market and our costs per barrel have continued to improve in early 2016. Our track record of continually reducing our year-over-year non-energy operating costs is indicative of the effort we have put into driving continued efficiencies and operational excellence.

Our drive to efficient operations has delivered a substantial benefit in our environmental performance. Our greenhouse gas emissions performance remains well below the industry average and below many of the major sources of imported barrels into the North American market. Our efficiency with respect to water use and recycling rates is also in the top tier of the oil sands industry and we are continuing our efforts to reduce surface land impacts.

As we look beyond the wellhead, we have also maintained efforts to increase the value we receive for our barrels in the market. In early 2016, we doubled our available capacity to reach the U.S. Gulf Coast to 50,000 barrels per day. This link remains an important part of our marketing strategy and we feel we are well positioned in the current environment of uncertainty around pipeline access to tide water.

Similarly, we have advanced preliminary work for our planned HI-Q® Pilot Project and Diluent

Removal Facility. While distinct projects in their own right, these initiatives share the goal of reducing our requirements for diluent, a light hydrocarbon blended with heavy oil for shipping. These are exciting opportunities because reducing the diluent volumes we require reduces our cash costs. And, because diluent makes up about one third of our blend barrels, we can also reduce our shipping costs.

As we look forward, we are positioning MEG for the future development of our three billion barrel proved-plus-probable resource base. This resource base, as confirmed by independent evaluators is of very high quality.

We have in hand regulatory approvals for up to 210,000 barrels per day of production at Christina Lake and have regulatory applications in process for a further 120,000 and 160,000 barrels per day, respectively, at our Surmont and May River properties. Both Surmont and May River are relatively close to our Christina Lake project and share the advantages of similar geology and the ability to leverage expertise, technology and infrastructure that we already have in place. Altogether, Christina Lake, Surmont and May River add up to a proposed volume of nearly half a million barrels per day, all of which are 100% controlled by MEG.

As we continue our work on developing our resource base, we are also addressing our financial base. Underlying our plans is a financial foundation that continues to maintain significant liquidity. In addition to 2016 operating cash flow, MEG has maintained a strong cash position and has access to an undrawn five-year US$2.5 billion dollar bank facility. Our bank facility, as well as all of our current outstanding debt, is free of financial maintenance covenants and our first long-term debt maturity is not due until 2020.

In line with our overall business model, we have taken a long-term approach to our capital structure and we are well-positioned to work through the

Bill McCaffrey

current commodity price cycles. To provide further strength to our balance sheet, we have recently entered into commodity price hedges to cover both a portion of our diluent requirements and crude blend sales.

To be certain, these hedges are not about predicting market prices; they are, rather, about providing predictability to our cash flows as we look toward future developments. We will continue with our efforts to divest our 50 per cent interest in the Access pipeline, taking into account the short, medium and long-term interests of the company and our stakeholders.

All of these elements are important components to our strategy of building shareholder value. With the combination of MEG's exceptional operating performance, low-capital growth strategy, high-quality resource base, and strong financial base, I believe we are very well positioned for the future.

On behalf of your Board of Directors and the MEG team, I thank you for your support.

W. J. McCaffrey

Bill McCaffrey
President and CEO

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, 2015 was approved by the Board of Directors on March 3, 2016. 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, 2015 and its Annual Information Form ("AIF") for the year ended December 31, 2015. This MD&A and the audited consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in thousands of Canadian dollars, except where otherwise indicated.

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1. OVERVIEW

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, please refer to the Corporation's AIF.

The Corporation has identified two commercial SAGD projects; the Christina Lake Project and the Surmont Project. The Christina Lake Project has received regulatory approval for 210,000 barrels per day ("bbls/d") of production and MEG has applied for regulatory approval for 120,000 bbls/d of production at the Surmont Project. 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 "May River Regional Project" and the "Growth Properties." The Corporation is pursuing these opportunities for development and anticipates filing regulatory applications in 2016 for the May River Regional Project. 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, Phases 1 and 2, commenced production in 2008 and 2009, respectively, with a combined designed capacity of 25,000 bbls/d. In 2012, the Corporation announced the RISER initiative, which is designed to increase production from existing assets at lower capital and operating costs using a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including debottlenecking and expansions (collectively, "RISER"). Phase 2B, an expansion with an initial designed capacity of 35,000 bbls/d, commenced production in the fourth quarter of 2013 and was successfully ramped up throughout 2014. Due to the successful ramp-up of Phase 2B, in combination with the success achieved from applying RISER, the Corporation achieved average production in excess of 80,000 bbls/d from the Christina Lake Project during the fourth quarter of 2014. Bitumen production for the year ended December 31, 2014 averaged 71,186 bbls/d and for the year ended December 31, 2015 averaged 80,025 bbls/d.

The Corporation is currently focused on the continuing application of RISER. The Corporation anticipates this strategy will allow the Corporation to increase production more efficiently and at lower capital intensity.

In addition, MEG has filed for regulatory applications for the Surmont Project, which is situated along the same geological trend as the Christina Lake Project and has an anticipated designed capacity of approximately 120,000 bbls/d over multiple phases. MEG filed a regulatory application for the project in September 2012. The proposed project is expected to use SAGD technology and include multi-well production pads, electricity and steam cogeneration and other facilities similar to MEG's current Christina Lake Project. The Surmont Project is located approximately 30 miles north of the Corporation's Christina Lake Project. This area has been extensively explored and developed for natural gas projects, and more recently for oil sands resources. Other thermal recovery projects are already operating in this area.

MEG also 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. In 2014, MEG completed an expansion of the Access Pipeline to accommodate anticipated increases in production from the Christina Lake Project as well as provide expansion capacity for future production volumes from the Surmont Project, the May River Regional Project and the Growth Properties. MEG's 50% interest of the capacity in the expanded 42-inch line is approximately 200,000 bbls/d of blended bitumen. The system's former 24-inch blend line was converted to diluent service during the third quarter of 2015.

On August 31, 2015, the Corporation announced the formation of a committee of the Board of Directors and that it had retained BMO Capital Markets and Credit Suisse to assist management in the review of options available to the Corporation to utilize its interest in the Access Pipeline to reduce the financial leverage of the Corporation. The potential monetization of MEG's 50% holding in the Access Pipeline continues to be a key priority. The Corporation is working diligently to complete this process, while ensuring the transaction is in the long-term interest of MEG's shareholders.

In addition to the Access Pipeline, MEG 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 is connected to local and export markets by pipeline, in addition to being pipeline connected 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.

2. SUMMARY ANNUAL INFORMATION

($000s, except per share amounts)	2015	2014	2013
Revenue[(1)]	**1,925,916**	2,829,964	1,334,497
Net loss	**(1,169,671)**	(105,538)	(166,405)
Per share – basic	**(5.21)**	(0.47)	(0.75)
Per share – diluted	**(5.21)**	(0.47)	(0.75)
Total assets	**9,400,269**	9,930,108	9,447,741
Total non-current liabilities	**5,474,106**	4,700,771	4,209,719

(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 2015, revenue decreased 32% from 2014, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, partially offset by an increase in production volumes from the Christina Lake Project.

During 2014, revenue increased 112% from 2013 primarily as a result of the increase in production from the Christina Lake Project due to the successful ramp-up of Christina Lake Phase 2B and the implementation of RISER at the Christina Lake Project.

Net Loss

The net loss in 2015 increased from the net loss recorded in 2014 primarily due to higher unrealized foreign exchange losses attributable to a decrease in value of the Canadian dollar relative to the U.S. dollar, which impacts the translation of the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. In addition to higher unrealized foreign exchange losses in 2015, the net loss was impacted by lower bitumen realization, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, higher transportation costs associated with transporting volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, an increase in depletion and depreciation expense as a result of an increase in bitumen production volumes and an increase in interest expense due to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense. These factors were partially offset by an increase in bitumen sales volumes and lower royalties.

The net loss in 2014 decreased from the net loss recorded in 2013 primarily due to an increase in bitumen realization as a result of an increase in sales volumes and an increase in the average blend sales price. This increase was partially offset by an increase in depletion and depreciation expense and an increase in operating expenses as a result of an increase in bitumen production volumes, higher unrealized foreign exchange losses and an increase in interest expense. Higher unrealized foreign exchange losses are attributable to a decrease in value of the Canadian dollar relative to the U.S. dollar, which impacts the translation of the Corporation's U.S. dollar denominated debt and U.S. dollar cash and cash equivalents. Interest expense increased primarily as a result of an increase in average debt outstanding in 2014 compared to 2013, in addition to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense.

Total Assets

Total assets as at December 31, 2015 decreased compared to December 31, 2014 primarily due to an increase in depletion and depreciation expense as a result of an increase in bitumen production volumes and a decrease in cash and cash equivalents. The depletion and depreciation expense in 2015 was in excess of capital investment incurred during 2015, as the Corporation has been focused on reducing capital spending until there is a sustained improvement in crude oil pricing. The cash and cash equivalents balance as at December 31, 2015 decreased compared to December 31, 2014 primarily due to the settlement of accounts payable related to 2014 capital investment activity.

Total assets increased as at December 31, 2014 compared to December 31, 2013 primarily due to capital investment in the Christina Lake Project, the RISER initiative, the Access Pipeline and the Stonefell Terminal, as well as resource definition at the Surmont Project and the Growth Properties.

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, 2015 increased compared to December 31, 2014 primarily due to the Corporation recognizing an unrealized foreign exchange loss on the translation of the U.S. dollar denominated debt as a result of weakening of the Canadian dollar compared to the U.S. dollar by approximately 19% during the year ended December 31, 2015.

Total non-current liabilities as at December 31, 2014 increased compared to December 31, 2013 primarily due to the Corporation recognizing an unrealized foreign exchange loss on the translation of the U.S. dollar denominated debt as a result of weakening of the Canadian dollar compared to the U.S. dollar by approximately 9% during the year ended December 31, 2014.

3. OPERATIONAL AND FINANCIAL HIGHLIGHTS

As a result of the ongoing global imbalance between supply and demand for crude oil, the Corporation's operating and financial results for 2015 continued to be impacted by the low commodity price environment. The C$/bbl WTI average price for 2015 decreased 39% compared to 2014.

From December 31, 2014, the value of the Canadian dollar relative to the U.S. dollar has decreased 19%. As the value of the Canadian dollar weakens the translated value of the Corporation's U.S. dollar denominated debt and related interest expense increases.

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:

($000s, except as indicated)	**2015**	**2014**
Bitumen production - bbls/d	**80,025**	71,186
Bitumen realization - $/bbl	**30.63**	62.67
Net operating costs - $/bbl(1)	**9.39**	12.06
Non-energy operating costs - $/bbl	**6.54**	8.02
Cash operating netback - $/bbl(2)	**15.72**	44.87
Cash flow from operations(3)	**49,460**	791,458
Per share, diluted(3)	**0.22**	3.52
Operating earnings (loss)(3)	**(374,374)**	247,353
Per share, diluted(3)	**(1.67)**	1.10
Revenue(4)	**1,925,916**	2,829,964
Net loss(5)	**(1,169,671)**	(105,538)
Per share, basic	**(5.21)**	(0.47)
Per share, diluted	**(5.21)**	(0.47)
Total cash capital investment(6)	**257,178**	1,237,539
Cash and cash equivalents	**408,213**	656,097
Long-term debt	**5,190,363**	4,350,421

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

(2) *Cash operating netbacks are calculated by deducting the related diluent, transportation, operating expenses and royalties from proprietary sales volumes and power revenues, on a per barrel of bitumen sales volume basis.*

(3) *Cash flow from 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. These non-GAAP measures are reconciled to net loss and net cash provided by operating activities 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 (Loss) and Comprehensive Income (Loss).*

(5) *Includes an unrealized foreign exchange loss on translation of the U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents of $785.3 million for the year ended December 31, 2015 and $333.1 million for the year ended December 31, 2014.*

(6) *Defined as total capital investment excluding dispositions, capitalized interest and non-cash items.*

Bitumen Production

Bitumen production for the year ended December 31, 2015 averaged 80,025 bbls/d compared to 71,186 bbls/d for the year ended December 31, 2014. The increase in production volumes is primarily due to efficiency gains associated with RISER at the Christina Lake Project. The implementation of the RISER initiative has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production to sustain current production levels. These increases in production were partially offset by a reduction in bitumen volumes as a result of a planned turnaround in the second quarter of 2015, which was longer in duration and had a greater impact on production volumes than the turnaround for the same period in 2014. In addition, forest fires near the Christina Lake Project extended the duration of time required to complete the 2015 turnaround. During 2014, MEG successfully ramped up Phase 2B and in combination with the success achieved from applying RISER to Phases 1 and 2, increased average bitumen production from 58,643 bbls/d in the first quarter of 2014 to 80,349 bbls/day in the fourth quarter of 2014.

Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary petroleum revenue ("blend sales revenue"), net of the cost of diluent, 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 region 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 the cost of diluent is effectively recovered in the sales price of the blended product. The cost of diluent 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.

For the year ended December 31, 2015, average bitumen realization decreased to $30.63 per barrel compared to $62.67 per barrel for the year ended December 31, 2014. The decrease in bitumen realization is primarily a result of the significant decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue and higher relative pricing per barrel for purchased diluent.

The C$/bbl WTI price averaged $62.40 per barrel during the year ended December 31, 2015 compared to $102.74 per barrel during the year ended December 31, 2014. The WTI:WCS differential widened to an average of 27.7% for the year ended December 31, 2015 compared to 21.1% for the year ended December 31, 2014.

Net Operating Costs

Net operating costs are comprised of the sum of non-energy operating costs and energy operating costs, which are reduced by power revenue. Non-energy operating costs represent production operating activities excluding energy operating costs. 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 at the Corporation's cogeneration facilities at the Christina Lake Project.

Net operating costs for the year ended December 31, 2015 averaged $9.39 per barrel compared to $12.06 per barrel for the year ended December 31, 2014. The decrease in net operating costs is attributable to a per barrel decrease in energy and non-energy operating costs, partially offset by a decrease in power revenue.

- Energy operating costs decreased to $3.84 per barrel for the year ended December 31, 2015 compared to $6.30 per barrel for the same period in 2014. The Corporation's energy operating costs decreased primarily as a result of the decline in natural gas prices, which decreased to an average of $3.11 per mcf for the year ended December 31, 2015 compared to $4.62 per mcf for the same period in 2014.

- Non-energy operating costs decreased to $6.54 per barrel for the year ended December 31, 2015 compared to $8.02 per barrel for the same period in 2014. Non-energy operating costs for 2014 include $0.51 per barrel for annual inspection and maintenance activities at the Christina Lake facilities. The decrease in non-energy operating costs is primarily the result of efficiency gains and a continued focus on cost management and holding absolute costs relatively constant during a period of increasing sales volumes, as these costs are now spread over a greater number of barrels. Consistent with the Corporation's capitalization policy, the 2015 turnaround costs have been capitalized, as the work performed will benefit future years of operations. As a result, the cost of the 2015 turnaround is treated as a component of capital investment and will be depreciated on a straight line basis over the period to the next turnaround.

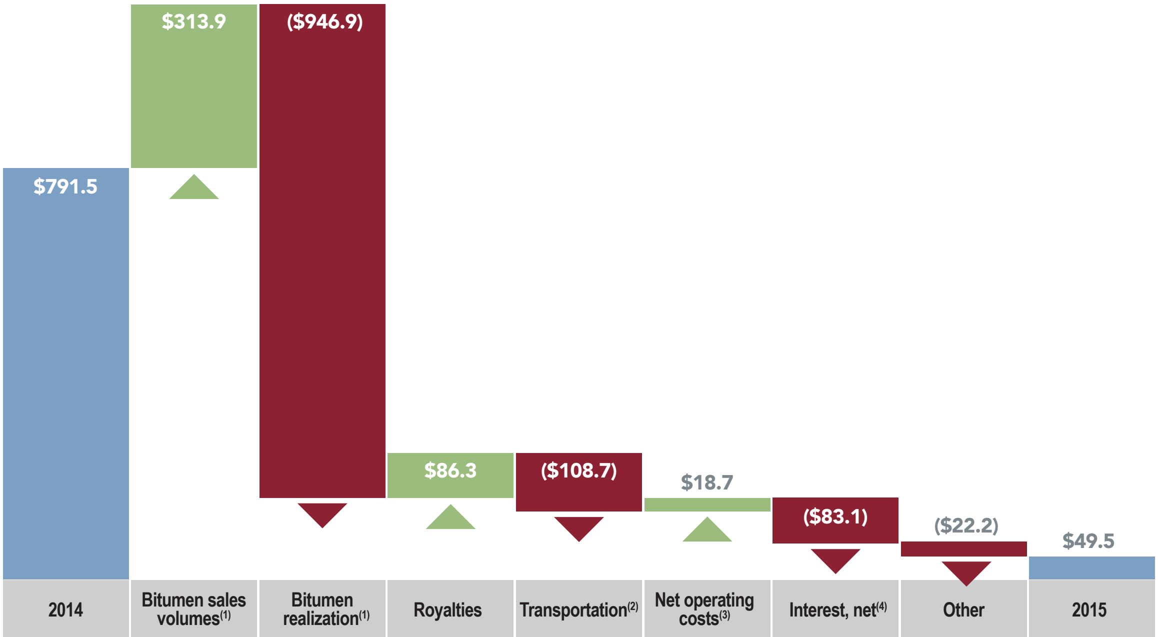
- Power revenue decreased to $0.99 per barrel for the year ended December 31, 2015 compared to $2.26 per barrel for the same period in 2014. The decrease is primarily due to a decrease in the Corporation's realized power price. The Corporation's realized power price during the year ended December 31, 2015 decreased to $27.48 per megawatt hour compared to $48.83 per megawatt hour for the same period in 2014. Power revenue had the effect of offsetting 26% of energy operating costs during the year ended December 31, 2015 compared to offsetting 36% of energy operating costs during the same period in 2014.

Cash Operating Netback

Cash operating netback for the year ended December 31, 2015 was $15.72 per barrel compared to $44.87 per barrel for the year ended December 31, 2014. The decrease in the cash operating netback is primarily due to a decrease in bitumen realization as a result of the significant decline of U.S. crude oil benchmark pricing.

Cash Flow from Operations – Year Ended December 31, 2015

($ millions)



(1) *Net of diluent.*

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

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

(4) *Includes cash interest expense, net of capitalized interest, and realized gain/loss on interest rate swaps less interest income.*

Cash flow from operations was $49.5 million for the year ended December 31, 2015 compared to cash flow from operations of $791.5 million for the year ended December 31, 2014. Cash flow from operations decreased primarily due to lower bitumen realization, higher transportation and higher interest costs, partially offset by an increase in bitumen sales volumes and lower royalties. The decrease in bitumen realization and decrease in royalties is directly correlated to the significant decline of U.S. crude oil benchmark pricing. Transportation expense increased primarily due to the cost of transporting blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, which commenced operations in the fourth quarter of 2014. During 2015, the Corporation's transportation costs have increased to accommodate a greater proportion of blend sales now being directly sold to refineries at the U.S. Gulf Coast. The Corporation will have increased access to the U.S. Gulf Coast on the Flanagan-Seaway pipeline system in January 2016. Interest expense increased primarily as a result of the weakening of the Canadian dollar relative to the U.S. dollar, as the Corporation's debt is denominated in U.S. dollars and lower capitalized interest.

Operating Earnings (Loss)

The Corporation recognized an operating loss of $374.4 million for the year ended December 31, 2015 compared to operating earnings of $247.4 million for the year ended December 31, 2014. The decrease was due to lower bitumen realization, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, higher transportation costs, an increase in depletion and depreciation expense and an increase in interest expense. These items were partially offset by an increase in bitumen sales volumes and lower royalties.

Revenue

Revenue for the year ended December 31, 2015 totalled $1.9 billion compared to $2.8 billion for the year ended December 31, 2014. Revenue decreased primarily due to a decrease in blend sales revenue as a result of the significant decline of U.S. crude oil benchmark pricing. Revenue represents the total of Petroleum revenue, net of royalties and Other revenue.

Net Loss

The Corporation recognized a net loss of $1.2 billion for the year ended December 31, 2015 compared to a net loss of $105.5 million for the year ended December 31, 2014. The net loss for the year ended December 31, 2015 included a net unrealized foreign exchange loss of $785.3 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. The net loss for the year ended December 31, 2014 included a net unrealized foreign exchange loss of $333.1 million on U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. In addition to a higher unrealized foreign exchange loss for the year ended December 31, 2015 compared to December 31, 2014, the net loss was impacted by lower bitumen realization, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, higher transportation costs, an increase in depletion and depreciation expense and an increase in interest expense. These items were partially offset by an increase in bitumen sales volumes and lower royalties.

Total Cash Capital Investment

Total cash capital investment during the year ended December 31, 2015 totalled $257.2 million compared to $1.2 billion for the year ended December 31, 2014. Capital investment in 2015 was primarily directed towards sustaining and maintenance activities, as the Corporation has been focused on reducing capital spending until there is a sustained improvement in crude oil pricing.

Capital Resources

The Corporation's cash and cash equivalents balance totalled $408.2 million as at December 31, 2015 compared to a cash and cash equivalents balance of $656.1 million as at December 31, 2014. The Corporation's cash and cash equivalents balance decreased primarily due to lower cash flow from operations directly correlated to the significant decline of U.S. crude oil benchmark pricing, costs incurred related to the 2015 capital program and the use of cash to settle accounts payable related to 2014 capital investment activity. These factors were partially offset by proceeds of $110.0 million from the sale of a non-core undeveloped oil sands asset in the fourth quarter of 2015.

All of the Corporation's long-term debt is denominated in U.S. dollars. As a result of the decrease in the value of the Canadian dollar relative to the U.S. dollar, long-term debt increased to C$5.2 billion as at December 31, 2015 from C$4.4 billion as at December 31, 2014. All of MEG'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. The first maturity of any of the Corporation's long-term debt obligations is March 2020.

As at December 31, 2015, the Corporation's capital resources included $408.2 million of cash and cash equivalents, an additional undrawn US$2.5 billion syndicated revolving credit facility, and a US$500 million guaranteed letter of credit facility, under which US$179.2 million of letters of credit have been issued. During the fourth quarter of 2014, the Corporation increased the syndicated revolving credit facility from US$2.0 billion to US$2.5 billion and extended the maturity of the revolving credit facility to November 2019. During the fourth quarter of 2014, the Corporation obtained a five-year US$500 million guaranteed letter of credit facility guaranteed by Export Development Canada ("EDC"). The facility matures November 2019. Letters of credit issued under the facility with EDC will not consume capacity of the revolving credit facility. Similar to the Corporation's long-term debt, the revolving credit facility is "covenant lite" in structure.

4. OUTLOOK

Summary of 2015 Guidance	Initial Guidance(1)	Revised Guidance(1)	Annual Results
Capital investment - $ millions	$305	$280	$257
Bitumen production - bbls/d	78,000 – 82,000	78,000 – 82,000	80,025
Non-energy operating costs - $/bbl	$8.00 – $10.00	$6.90 – $7.10	$6.54

(1) Initial guidance was announced on December 17, 2014. Revised guidance was announced in the fourth quarter of 2015.

Initially, the Corporation disclosed on December 17, 2014 that the 2015 planned capital program was anticipated to be $305 million. In the fourth quarter of 2015, as the Corporation implemented multiple initiatives to adapt to a low crude oil price environment, the Corporation announced revised capital investment for 2015 of $280 million. The $257 million of cash capital investment incurred during 2015 was lower than anticipated primarily due to decreased activity in response to the continued decline in global crude oil prices, in conjunction with ongoing capital efficiency initiatives.

Annual bitumen production averaged 80,025 bbls/d, meeting the Corporation's 2015 guidance range of 78,000 to 82,000 bbls/d, and represents production growth of 12% over the 2014 annual average production.

In December 2014, the Corporation announced annual non-energy operating cost guidance to be in the range of $8.00 to $10.00 per barrel. In the second quarter of 2015, the Corporation revised this annual guidance to be in the range of $7.30 to $9.30 per barrel, and subsequently, in the fourth quarter of 2015, revised this annual guidance to be in the range of $6.90 to $7.10 per barrel. Annual non-energy operating costs were $6.54/bbl, representing a 7% reduction to the latest 2015 guidance of $6.90 to $7.10 per barrel. Non-energy operating costs in the fourth quarter of 2015 were less than anticipated due to the Corporation's focus on ongoing cost control initiatives and associated field operating cost efficiencies.

Summary of 2016 Guidance	Initial Guidance(1)	Revised Guidance(1)
Capital investment - $ millions	$328	$170
Bitumen production - bbls/d	80,000 – 83,000	80,000 – 83,000
Non-energy operating costs - $/bbl	$6.75 – $7.75	$6.75 – $7.75

(1) Initial guidance was announced on December 4, 2015. Revised guidance was announced on February 4, 2016.

On December 4, 2015, the Corporation announced a 2016 capital budget of $328 million. In response to the continuing deterioration and volatility of global crude oil markets, the Corporation has reduced its 2016 capital budget from $328 million to $170 million.

As a result of ongoing capital and operational initiatives, previously released 2016 operating guidance remains unchanged. The Corporation's 2016 annual bitumen production volumes are targeted to be in the range of 80,000 to 83,000 bbls/d compared to the average bitumen production for the year ended December 31, 2015 of 80,025 bbls/d. Non-energy operating costs are targeted to be in the range of $6.75 to $7.75 per barrel.

The Corporation expects to fund its 2016 capital budget with existing cash on hand as at December 31, 2015. The Corporation's cash balance as at December 31, 2015 was $408 million.

On August 31, 2015, the Corporation announced the formation of a committee of the Board of Directors and that it had retained BMO Capital Markets and Credit Suisse to assist management in the review of options available to the Corporation to utilize its interest in the Access Pipeline to reduce the financial leverage of the Corporation. The potential monetization of MEG's 50% holding in the Access Pipeline continues to be a key priority. The Corporation is working diligently to complete this process, while ensuring the transaction is in the long-term interest of MEG's shareholders.

5. BUSINESS ENVIRONMENT

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

	Year ended December 31		2015				2014			
	2015	**2014**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Average Commodity Prices										
Crude oil prices										
Brent (US$/bbl)	**53.62**	99.66	**44.71**	51.17	63.50	55.16	76.98	103.39	109.77	107.90
WTI (US$/bbl)	**48.80**	93.00	**42.18**	46.43	57.94	48.63	73.15	97.16	102.99	98.68
WTI (C$/bbl)	**62.40**	102.74	**56.32**	60.79	71.24	60.35	83.08	105.84	112.31	108.89
Differential – Brent:WTI (US$/bbl)	**4.82**	6.66	**2.53**	4.74	5.56	6.53	3.83	6.23	6.78	9.22
Differential – Brent:WTI (%)	**9.0%**	6.7%	**5.7%**	9.3%	8.8%	11.8%	5.0%	6.0%	6.2%	8.5%
WCS (C$/bbl)	**45.12**	81.10	**36.97**	43.29	56.98	42.13	66.74	83.82	90.44	83.41
Differential – WTI:WCS (C$/bbl)	**17.29**	21.63	**19.35**	17.50	14.25	18.22	16.34	22.02	21.87	25.48
Differential – WTI:WCS (%)	**27.7%**	21.1%	**34.4%**	28.8%	20.0%	30.2%	19.7%	20.8%	19.5%	23.4%
Condensate prices										
C5+ at Edmonton (C$/bbl)	**60.30**	102.92	**55.57**	57.89	71.17	56.59	81.98	101.72	114.72	113.26
Condensate at Mont Belvieu, Texas (US$/bbl)	**45.23**	83.21	**40.76**	41.27	52.89	46.01	62.47	88.49	92.90	88.96
Natural gas prices										
AECO (C$/mcf)	**2.71**	4.50	**2.57**	2.89	2.64	2.74	3.58	4.00	4.70	5.69
Electric power prices										
Alberta power pool (C$/MWh)	**33.40**	49.37	**21.19**	26.04	57.25	29.14	30.55	63.91	42.43	60.58
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**1.2788**	1.1047	**1.3353**	1.3093	1.2294	1.2411	1.1357	1.0893	1.0905	1.1035
C$ equivalent of 1 US$ - period end	**1.3840**	1.1601	**1.3840**	1.3394	1.2474	1.2683	1.1601	1.1208	1.0676	1.1053

Crude Oil Pricing

Brent crude is the primary world price benchmark for global light sweet crude oil. The Brent benchmark price averaged US$53.62 per barrel for the year ended December 31, 2015 compared to US$99.66 per barrel for the year ended December 31, 2014. The global supply of crude oil is currently greater than demand, which has resulted in a decrease in prices.

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 royalties on the Corporation's bitumen sales. The WTI price averaged US$48.80 per barrel for the year ended December 31, 2015 compared to US$93.00 per barrel for the year ended December 31, 2014. The global supply of crude oil is currently greater than demand, which has resulted in a decrease in prices.

The WCS benchmark reflects North American prices at Hardisty, Alberta. WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. WCS typically trades at a differential below the WTI benchmark price. The WTI:WCS differential averaged $17.29 per barrel or 27.7% for the year ended December 31, 2015, compared to $21.63 per barrel or 21.1% for the same period in 2014.

In order to facilitate pipeline transportation, MEG uses condensate as diluent for blending with the Corporation's bitumen. When the demand for condensate in Alberta exceeds supply, Edmonton condensate prices may be impacted by U.S. Gulf Coast condensate prices plus the costs associated with transporting the condensate from the U.S. Gulf Coast to Edmonton. Condensate prices, benchmarked at Edmonton, averaged $60.30 per barrel for the year ended December 31, 2015 compared to $102.92 per barrel for the year ended December 31, 2014. Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$45.23 per barrel for the year ended December 31, 2015 compared to US$83.21 per barrel for the year ended December 31, 2014.

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 $2.71 per mcf for the year ended December 31, 2015 compared to $4.50 per mcf for the year ended December 31, 2014. The North American natural gas supply is currently greater than demand, which has resulted in a decrease in prices. Natural gas prices have fallen to multi-year lows due to high inventory levels caused by unseasonably warm temperatures during the fourth quarter of 2015. Average prices have fallen 40% in 2015 from the 2014 average.

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 $33.40 per megawatt hour for the year ended December 31, 2015 compared to $49.37 per megawatt hour for the same period in 2014. The decline in the Alberta power pool price is primarily due to a surplus of power generation capacity in the province.

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 cost of diluent, as blend sales prices and cost of diluent 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 the cost of diluent and principal and interest payments, while an increase in the value of the Canadian dollar has a negative impact on blend sales revenue and a positive impact on the cost of diluent 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. During the year ended December 31, 2015, the Canadian dollar weakened in value by approximately 19% from December 31, 2014, when the rate was 1.1601.

6. RESULTS OF OPERATIONS

	2015	2014
Bitumen production – bbls/d	**80,025**	71,186
Steam to oil ratio (SOR)	**2.5**	2.5

Bitumen Production

Production for the year ended December 31, 2015 averaged 80,025 bbls/d compared to 71,186 bbls/d for the year ended December 31, 2014. The increase in production volumes is primarily due to efficiency gains associated with RISER at the Christina Lake Project. The implementation of the RISER initiative has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production to sustain current production levels. These increases in production were partially offset by a reduction in production volumes as a result of a planned turnaround in the second quarter of 2015, which was longer in duration and had a greater impact on production volumes than the turnaround for the same period in 2014. In addition, forest fires near the Christina Lake Project extended the duration of time required to complete the 2015 turnaround.

Steam to Oil Ratio

The Corporation continues to focus on increasing production and maintaining efficiency of current production through a lower SOR, which 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 SOR averaged 2.5 during the year ended December 31, 2015 and during the year ended December 31, 2014.

Operating Cash Flow

($000)	2015	2014
Petroleum revenue – proprietary[1]	**$ 1,799,154**	$ 2,701,801
Diluent	**(893,995)**	(1,163,637)
	905,159	1,538,164
Royalties	**(20,765)**	(107,074)
Transportation expense	**(156,382)**	(64,442)
Operating expenses	**(306,725)**	(351,534)
Power revenue	**29,239**	55,352
Transportation revenue	**13,824**	30,625
Operating cash flow[2]	**$ 464,350**	$ 1,101,091

(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.*

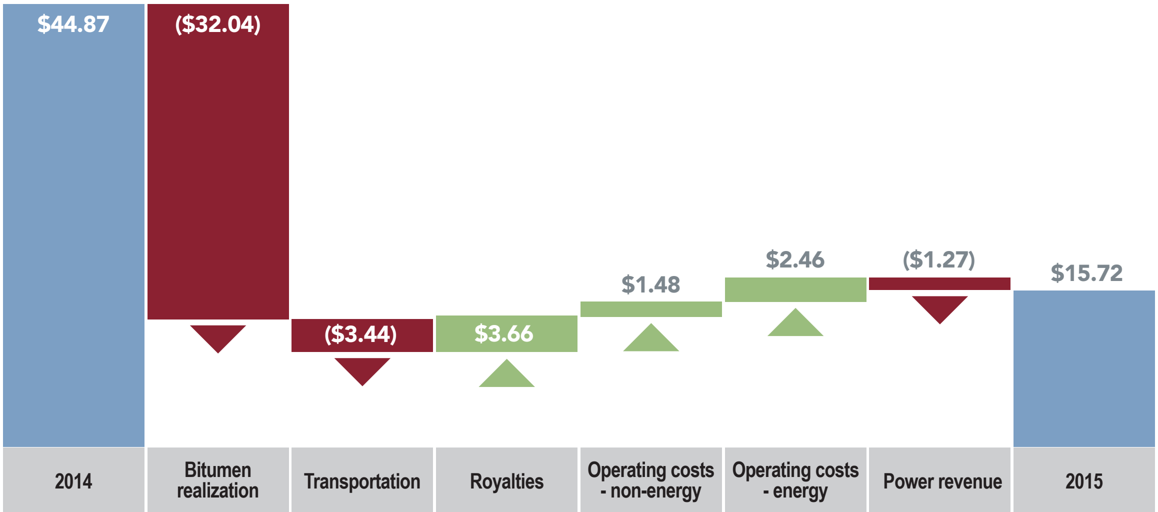
(2) *A non-GAAP measure as defined in the "NON-GAAP MEASURES" section of this MD&A.*

Blend sales revenue for the year ended December 31, 2015 was $1.8 billion compared to $2.7 billion for the year ended December 31, 2014. The decrease in blend sales revenue is due to a 45% decrease in the average realized blend price partially offset by a 20% increase in blend sales volumes. The cost of diluent for the year ended December 31, 2015 was $894.0 million compared to $1.2 billion for the year ended December 31, 2014. The cost of diluent decreased primarily due to the decrease in condensate prices partially offset by higher volumes of diluent required for the increased blend sales volumes.

Operating cash flow decreased primarily due to lower blend sales revenue as a result of the significant decline of U.S. crude oil benchmark pricing and higher transportation costs to transport blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline. These factors were partially offset by a decrease in the cost of diluent, lower royalties and lower operating expenses.

Cash Operating Netback

($/bbl)



The following table summarizes the Corporation's cash operating netback for the periods indicated:

($/bbl)	**2015**	**2014**
Bitumen realization[1]	**$ 30.63**	$ 62.67
Transportation[2]	**(4.82)**	(1.38)
Royalties	**(0.70)**	(4.36)
	25.11	56.93
Operating costs – non-energy	**(6.54)**	(8.02)
Operating costs – energy	**(3.84)**	(6.30)
Power revenue	**0.99**	2.26
Net operating costs	**(9.39)**	(12.06)
Cash operating netback	**$ 15.72**	$ 44.87

(1) *Blend sales net of diluent costs.*

(2) *Defined as transportation expense less transportation revenue. Transportation costs include 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 averaged $30.63 per barrel for the year ended December 31, 2015 compared to $62.67 per barrel for the year ended December 31, 2014. The decrease in bitumen realization is primarily a result of the significant decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue.

For the year ended December 31, 2015, the Corporation's cost of diluent was $67.72 per barrel of diluent compared to $105.94 per barrel of diluent for the year ended December 31, 2014. The decrease in the cost of diluent is primarily a result of the significant decline of U.S. crude oil benchmark pricing.

Transportation

Transportation costs averaged $4.82 per barrel for the year ended December 31, 2015 compared to $1.38 per barrel for the year ended December 31, 2014. Transportation expense increased primarily due to the cost of transporting blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, which commenced operations in the fourth quarter of 2014. During 2015, the Corporation's transportation costs have increased to accommodate a greater proportion of blend sales now being directly sold to refineries at the U.S. Gulf Coast. These increasing direct sales to refineries at the U.S. Gulf Coast are a result of MEG's strategy of broadening market access to world prices to improve netbacks. In addition, there were lower transportation revenues from third parties.

Royalties

The Corporation's royalty expense is based on price-sensitive royalty rates set by the Government of Alberta. The applicable royalty rates change dependent upon whether a project is pre-payout or post-payout, with payout being defined as the point in time when a project has generated enough net revenues to recover its cumulative costs. The royalty rate applicable to pre-payout oil sands operations starts at 1% of bitumen sales and increases for every dollar that the WTI crude oil price in Canadian dollars is priced above $55 per barrel, to a maximum of 9% when the WTI crude oil price is $120 per barrel or higher. All of the Corporation's projects are currently pre-payout.

Royalties averaged $0.70 per barrel during the year ended December 31, 2015 compared to $4.36 per barrel for the year ended December 31, 2014. The decrease in royalties is primarily attributable to the decrease in the Canadian dollar price of WTI and the decrease in bitumen realization.

Net Operating Costs

Non-energy operating costs

Non-energy operating costs decreased to $6.54 per barrel for the year ended December 31, 2015 compared to $8.02 per barrel for the year ended December 31, 2014. Non-energy operating costs were higher in the year ended December 31, 2014 as a result of the ongoing ramp-up of Phase 2B production. The decrease in non-energy operating costs for the year ended December 31, 2015 is primarily the result of efficiency gains and a continued focus on cost management and holding absolute costs relatively constant during a period of increasing sales volumes, as these costs are now spread over a greater number of barrels. Non-energy operating costs for the year ended December 31, 2014 also include $0.51 per barrel for annual inspection and maintenance activities at the Christina Lake facilities.

Historically, the Corporation has only performed annual inspection and maintenance activities on the Christina Lake facilities, with the associated costs expensed as non-energy operating costs. Consistent with the Corporation's capitalization policy, in the year ended December 31, 2015, turnaround costs have been capitalized, as the work performed will benefit future years of operations. As a result, the cost of the 2015 turnaround is treated as a component of capital investment and depreciated on a straight line basis over the period to the next turnaround.

Energy operating costs

Energy operating costs averaged $3.84 per barrel for the year ended December 31, 2015 compared to $6.30 per barrel for the year ended December 31, 2014. The decrease in energy operating costs on a per barrel basis is primarily attributable to the decrease in natural gas prices. The Corporation's natural gas purchase price averaged $3.11 per mcf during 2015 compared to $4.62 per mcf for 2014.

Power revenue

Power revenue averaged $0.99 per barrel for the year ended December 31, 2015 compared to $2.26 per barrel for the year ended December 31, 2014. The Corporation's average realized power sales price during the year ended December 31, 2015 was $27.48 per megawatt hour compared to $48.83 per megawatt hour for the same period in 2014. The decrease in the realized power sales price is primarily due to the current surplus of power generation capacity in the province of Alberta.

7. OTHER OPERATING RESULTS

Net Marketing Activity

($000)	2015	2014
Petroleum sales – third party	**$ 104,464**	$ 149,260
Purchased product and storage:		
Purchased product	**(101,928)**	(146,957)
Marketing and storage arrangements	**(27,687)**	(16,430)
	(129,615)	(163,387)
Net marketing activity[1]	**$ (25,151)**	$ (14,127)

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

Net marketing activity includes the Corporation's activities toward enhancing its ability to transport proprietary crude oil products to a wider range of markets in Canada and the United States. Accordingly, the Corporation has entered into marketing arrangements for barge, rail and U.S.-based pipelines and product storage arrangements. The intent of these arrangements is to optimize the value of all barrels sold to the marketplace. To the extent that the Corporation is not utilizing these arrangements for proprietary purposes, MEG purchases and sells third-party crude oil and related products and enters into transactions to optimize the returns on these marketing and storage arrangements.

Depletion and Depreciation

($000)	2015	2014
Depletion and depreciation expense	**$ 467,422**	$ 378,544
Depletion and depreciation expense per barrel of production	**$ 16.00**	$ 14.57

Depletion and depreciation expense for the year ended December 31, 2015 totalled $467.4 million compared to $378.5 million for the year ended December 31, 2014. The increase is primarily due to an increase in bitumen production volumes, an increase in depreciable costs and an increase in estimated future development costs for the year ended December 31, 2015, compared to the year ended December 31, 2014. Future development costs are a key element of the rate determination. The increase in the depletion and depreciation expense per barrel was primarily due to an increase in depreciable costs and an increase in the estimate of future development costs associated with the Corporation's proved reserves. Depletion and depreciation expense was $16.00 per barrel for the year ended December 31, 2015 compared to $14.57 per barrel for the year ended December 31, 2014.

General and Administrative

($000)	2015	2014
General and administrative expense	**$ 118,518**	$ 111,366
General and administrative expense per barrel of production	**$ 4.06**	$ 4.29

General and administrative expense for the year ended December 31, 2015 was $118.5 million compared to $111.4 million for the year ended December 31, 2014. The increase in general and administrative expense is primarily due to the lower rate of general and administrative expenses being capitalized in 2015 as a result of lower spending on major capital projects. General and administrative expense was $4.06 per barrel for the year ended December 31, 2015 compared to $4.29 per barrel for the year ended December 31, 2014. On a per barrel basis, general and administrative expense in 2015 was lower due to higher production volumes, as expenses are spread over a greater number of barrels.

Stock-based Compensation

($000)	2015	2014
Stock-based compensation expense	**$ 50,105**	$ 48,310

The fair value of compensation associated with the granting of stock options, restricted share units ("RSUs") and performance share units ("PSUs") to directors, officers, employees and consultants is recognized by the Corporation as stock-based compensation expense. Fair value is determined using the Black-Scholes option pricing model. Stock-based compensation expense for the year ended December 31, 2015 was $50.1 million compared to $48.3 million for the year ended December 31, 2014.

Research and Development

($000)	2015	2014
Research and development expense	**$ 7,497**	$ 6,003

Research and development expenditures related to the Corporation's research of crude quality improvement and related technologies have been expensed. Research and development expenditures were $7.5 million for the year ended December 31, 2015 compared to $6.0 million for the year ended December 31, 2014.

Gain on Disposition of Assets

($000)	2015	2014
Gain on disposition of assets	**$ 68,192**	$ –

In the fourth quarter of 2015, the Corporation completed a sale of a non-core undeveloped oil sands asset to an unrelated third party for proceeds of $110.0 million, resulting in a gain of $68.2 million.

Foreign Exchange Gain (Loss), Net

($000)	2015	2014
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ (852,422)**	$ (368,450)
US$ denominated cash, cash equivalents and other	**67,112**	35,301
Unrealized net loss on foreign exchange	**(785,310)**	(333,149)
Realized loss on foreign exchange	**(16,429)**	(5,480)
Foreign exchange loss, net	**$ (801,739)**	$ (338,629)

C$ equivalent of 1 US$		
Beginning of period	**1.1601**	1.0636
End of period	**1.3840**	1.1601

The Corporation recognized a net foreign exchange loss of $801.7 million for the year ended December 31, 2015 compared to a net foreign exchange loss of $338.6 million for the year ended December 31, 2014. The increase in the net foreign exchange loss is primarily due to an unrealized foreign exchange loss on the translation of the U.S. dollar denominated debt as a result of weakening of the Canadian dollar compared to the U.S. dollar by approximately 19% during the year ended December 31, 2015. During the year ended December 31, 2014, the Canadian dollar weakened in value by approximately 9%.

Net Finance Expense

($000)	2015	2014
Total interest expense	**$ 313,411**	$ 265,140
Less capitalized interest	**(56,449)**	(75,975)
Net interest expense	**256,962**	189,165
Accretion on decommissioning provision	**5,663**	4,535
Unrealized gain on derivative financial liabilities	**(13,289)**	(1,469)
Realized loss on interest rate swaps	**5,858**	5,056
Unrealized fair value gain on other assets	**–**	(429)
Net finance expense	**$ 255,194**	$ 196,858

Average effective interest rate(1)	**5.8%**	5.8%

(1) Defined as the weighted average interest rate applied to the U.S. dollar denominated senior secured term loan and senior unsecured notes outstanding, including the impact of interest rate swaps.

Total interest expense, before capitalization, for the year ended December 31, 2015 was $313.4 million compared to $265.1 million for the year ended December 31, 2014. Total interest expense for the year ended December 31, 2015 increased due to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense.

The Corporation recognized an unrealized gain on derivative financial liabilities of $13.3 million for the year ended December 31, 2015 compared to an unrealized gain of $1.5 million for the year ended December 31, 2014. These losses and gains relate to the change in fair value of the interest rate floor associated with the Corporation's senior secured term loan and the change in fair value of the Corporation's interest rate swap contracts.

The Corporation realized a loss on the interest swap contracts of $5.9 million for the year ended December 31, 2015, compared to a realized loss of $5.1 million for the year ended December 31, 2014.

Other Expenses

($000)	2015	2014
Onerous contracts	**$ 58,719**	$ –
Contract cancellation expense	**12,879**	16,455
Inventory write-down	**–**	19,668
Other expenses	**$ 71,598**	$ 36,123

The Corporation recognized other expenses of $71.6 million for the year ended December 31, 2015 compared to $36.1 million for the year ended December 31, 2014.

During the fourth quarter of 2015, the Corporation recognized an expense of $58.7 million relating to certain onerous Calgary office building lease contracts, determined as the difference between future lease obligations and estimated sublease recoveries.

For the year ended December 31, 2015, the Corporation recognized contract cancellation expense of $12.9 million primarily related to the termination of a marketing transportation contract, partially offset by a recovery recorded in the second quarter of 2015. For the year ended December 31, 2014, the Corporation recognized $16.5 million of field asset construction cancellation expense relating to the reduction of the Corporation's capital program.

During the fourth quarter of 2014, the Corporation recognized a bitumen blend inventory write-down of $19.7 million as a result of a decline in the value of bitumen blend inventory.

Income Tax Expense (Recovery)

($000)	2015	2014
Current income tax expense (recovery)	**$ (1,200)**	$ –
Deferred income tax expense (recovery)	**(90,733)**	85,776
Income tax expense (recovery)	**$ (91,933)**	$ 85,776

The Corporation recognized a current income tax recovery of $1.2 million for the year ended December 31, 2015 relating to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures.

The Corporation recognized a deferred income tax recovery of $90.7 million for the year ended December 31, 2015 compared to deferred income tax expense of $85.8 million for the year ended December 31, 2014.

In June 2015, the Government of Alberta enacted an increase in the Alberta corporate income tax rate from 10% to 12%, effective July 1, 2015. As a result, the Corporation increased its opening deferred income tax liability by $14.4 million, with a corresponding increase to deferred income tax expense.

The Corporation's effective tax rate on earnings is impacted by permanent differences and variances in taxable capital losses not recognized. The significant differences are:

- The permanent difference due to the non-taxable portion of unrealized foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the year ended December 31, 2015, the non-taxable loss was $426.2 million compared to a non-taxable loss of $184.2 million for the year ended December 31, 2014.
- Stock-based compensation expense is a permanent difference. Stock-based compensation expense for the year ended December 31, 2015 was $50.1 million compared to $48.3 million for the year ended December 31, 2014.
- During the year ended December 31, 2015, a deferred tax recovery of $5.5 million was recognized relating to a tax deduction available for the fair market value of vested RSUs.

The Corporation is not currently taxable. As at December 31, 2015, the Corporation had approximately $7.3 billion of available tax pools and had recognized a deferred income tax liability of $87.5 million. In addition, at December 31, 2015, the Corporation had $626.4 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects. As at December 31, 2015, the Corporation had not recognized the tax benefit related to $698.0 million of unrealized taxable capital foreign exchange losses.

8. SUMMARY OF QUARTERLY RESULTS

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

	2015				2014			
($ millions, except per share amounts)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Revenue[1]	**$444.5**	**$459.8**	**$554.6**	**$467.0**	$614.8	$706.4	$829.2	$679.6
Net earnings (loss)	**(297.3)**	**(427.5)**	**63.4**	**(508.3)**	(150.1)	(101.0)	249.0	(103.4)
Per share – basic	**(1.32)**	**(1.90)**	**0.28**	**(2.27)**	(0.67)	(0.45)	1.12	(0.46)
Per share – diluted	**(1.32)**	**(1.90)**	**0.28**	**(2.27)**	(0.67)	(0.45)	1.11	(0.46)

(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 for the eight most recent quarters has been impacted by the significant fluctuations in blend sales pricing and increases in production.

Net earnings (loss) during the periods noted was impacted by:

- increased blend sales volumes due to efficiency gains associated with RISER at the Christina Lake Project during 2015, which has allowed additional wells to be placed into production and the successful ramp-up of Christina Lake Phase 2B during 2014;
- fluctuations in blend sales pricing due to significant changes in the price of WTI and the differential between WTI and the Corporation's AWB;
- changes in the value of the Canadian dollar relative to the U.S. dollar as blend sales prices are determined by reference to U.S. crude oil benchmark pricing;
- the cost of diluent due to 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;
- higher transportation expense due to the cost of transporting blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, which commenced operations in the fourth quarter of 2014, to accommodate a greater portion of blend sales now being directly sold to refineries at the U.S. Gulf Coast;
- fluctuations in natural gas and power pricing;
- an increase in depletion and depreciation expense as a result of the increase in bitumen sales volumes, an increase in depreciable costs and higher estimated future development costs;
- foreign exchange gains and losses attributable to fluctuations in the rate of exchange between the Canadian and U.S. dollar in translating the Corporation's U.S. dollar denominated debt (net of U.S. dollar denominated cash and cash equivalents);
- an increase in interest expense due to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense; and
- recording an expense relating to onerous contracts in the fourth quarter of 2015.

9. NET CAPITAL INVESTING

($000)	**2015**	**2014**
Total cash capital investment	**$ 257,178**	$ 1,237,539
Capitalized interest	**56,449**	75,975
	313,627	1,313,514
Dispositions	**(41,827)**	–
Net capital investment	**$ 271,800**	$ 1,313,514

Total cash capital investment for the year ended December 31, 2015 was $257.2 million in comparison to $1.2 billion for the year ended December 31, 2014. Total cash capital investing for 2015 was primarily directed to sustaining and maintenance capital activities as the Corporation has been focused on reducing capital spending until there is a sustained improvement in crude oil pricing. During 2015, the Corporation divested of a non-core undeveloped oil sands asset for proceeds of $110.0 million.

The Corporation capitalizes interest associated with qualifying assets. A total of $56.4 million of interest was capitalized during the year ended December 31, 2015 in comparison to $76.0 million for the year ended December 31, 2014.

10. LIQUIDITY AND CAPITAL RESOURCES

($000)	2015	2014
Cash and cash equivalents	**$ 408,213**	$ 656,097
Senior secured term loan (December 31, 2015 – US$1.249 billion; December 31, 2014 – US$1.262 billion; due 2020)	**1,727,924**	1,463,466
US$2.5 billion revolver (due 2019)	**–**	–
6.5% senior unsecured notes (US$750.0 million; due 2021)	**1,038,000**	870,075
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,107,200**	928,080
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,384,000**	1,160,100
Total debt(1),(2)	**$ 5,257,124**	$ 4,421,721

(1) *Total debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The Corporation uses this non-GAAP measure to analyze leverage and liquidity. Total debt less the current portion of the senior secured term loan, unamortized financial derivative liability discount and unamortized deferred debt issue costs is equal to long-term debt as reported in the Corporation's consolidated financial statements as at December 31, 2015 and December 31, 2014.*

(2) *On February 3, 2016, Moody's Investors Service ("Moody's") downgraded the Corporation's Corporate Family Rating (CFR) to Caa2 from B1, Probability of Default Rating to Caa2-PD from B1-PD, secured bank credit facility rating to B3 from Ba2 and senior unsecured notes rating to Caa3 from B2. The Speculative Grade Liquidity Rating was lowered to SGL-2 from SGL-1. The rating outlook is negative. The Corporation's senior secured term loan and senior unsecured notes do not include any provision that would require any changes in payment schedules or terminations as a result of a credit downgrade.*

Capital Resources

As at December 31, 2015, the Corporation's available capital resources included $408.2 million of cash and cash equivalents and an undrawn US$2.5 billion syndicated revolving credit facility. The Corporation also has a US$500 million guaranteed letter of credit facility, under which US$179.2 million of letters of credit have been issued.

During the fourth quarter of 2014, the Corporation increased the syndicated revolving credit facility from US$2.0 billion to US$2.5 billion and extended the maturity of the revolving credit facility to November 2019. The revolving credit facility remains undrawn as at December 31, 2015. The transaction was completed through an amendment of MEG's existing credit facility. All of MEG'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. The first maturity of any of the Corporation's long-term debt obligations is March 2020. The term loan is being repaid in quarterly installments of US$3.25 million with the balance due March 31, 2020. During the fourth quarter of 2014, the Corporation obtained a five-year US$500 million guaranteed letter of credit facility guaranteed by Export Development Canada ("EDC"). The facility matures in November 2019. Letters of credit issued under the facility with EDC will not consume capacity of the revolving credit facility.

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 investments with counterparties that have an investment grade debt rating. 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 guidelines 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

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 interest rate swap contracts to effectively fix the interest rate at approximately 4.4% on US$748.0 million of the US$1.249 billion senior secured term loan until September 30, 2016.

MEG has implemented a strategic commodity risk management program through the use of derivative financial instruments to increase the predictability of the Corporation's cash flow. MEG's commodity risk management program is governed by a Risk Management Committee that follows guidelines and is subject to limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes.

At December 31, 2015, the Corporation had not entered into any commodity derivative financial instruments. In the first quarter of 2016, the Corporation entered into commodity derivative contracts to partially manage its exposure on condensate purchases, as outlined below:

Term	Contract	Volume (bbls/d)	Mont Belvieu/WTI %(1)
Apr. 1, 2016 – Dec. 31, 2016	Swap	6,000	82.8
Oct. 1, 2016 – Dec. 31, 2016	Swap	4,000	83.8
Jan. 1, 2017 – Dec. 31, 2017	Swap	10,000	81.3

(1) MEG has entered into swaps that effectively fix the average percentage differentials of condensate prices at Mont Belvieu, Texas to a percentage of WTI ($US/bbl).

Cash Flow Summary

($000)	2015	2014
Net cash provided by (used in):		
Operating activities	**$ 112,158**	$ 767,500
Investing activities	**(416,996)**	(1,312,440)
Financing activities	**(17,020)**	(13,336)
Foreign exchange gains on cash and cash equivalents held in foreign currency	**73,974**	35,301
Change in cash and cash equivalents	**$ (247,884)**	$ (522,975)

Cash Flow – Operating Activities

Net cash provided by operating activities totalled $112.2 million for the year ended December 31, 2015 compared to net cash provided by operating activities of $767.5 million for the year ended December 31, 2014. The decrease in cash flow from operating activities is primarily due to lower blend sales revenue, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, higher transportation and higher interest costs, partially offset by a decrease in the cost of diluent and lower royalties.

Transportation expense increased primarily due to the cost of transporting blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, which commenced operations in the fourth quarter of 2014, in addition to lower transportation revenues from third parties. Interest expense increased as a result of the weakening of the Canadian dollar relative to the U.S. dollar, as the Corporation's debt and interest payable are denominated in U.S. dollars.

Cash Flow – Investing Activities

Net cash used in investing activities for the year ended December 31, 2015 primarily consisted of $313.6 million in capital investment, including $56.4 million of capitalized interest, (refer to the "NET CAPITAL INVESTING" section of this MD&A for further details) and a $212.5 million decrease in the net change in non-cash investing working capital, primarily relating to the settlement of accounts payable related to 2014 capital investment activity. This was partially offset by proceeds of $110.0 million from a sale of a non-core undeveloped oil sands asset in the fourth quarter of 2015.

Net cash used in investing activities for the year ended December 31, 2014 primarily consisted of $1.3 billion in capital investment, including $76.0 million of capitalized interest (refer to the "NET CAPITAL INVESTING" section of this MD&A for further details) and a $3.3 million decrease in non-cash investing working capital.

Cash Flow – Financing Activities

Net cash used in financing activities for the year ended December 31, 2015 consisted of $17.0 million of debt principal repayment.

Net cash used in financing activities for the year ended December 31, 2014 consisted of $14.5 million of debt principal repayment and $10.0 million in financing costs. These amounts were partially offset by $11.2 million received from the exercise of stock options.

11. SHARES OUTSTANDING

As at December 31, 2015, the Corporation had the following share capital instruments outstanding and exercisable:

	Outstanding	Exercisable
Common shares	224,996,989	N/A
Convertible securities		
Stock options	9,925,313	5,431,712
RSUs and PSUs	3,280,112	N/A

As at February 26, 2016, the Corporation had 224,996,989 common shares, 9,753,669 stock options and 3,276,133 restricted share units and performance share units outstanding and 5,265,917 stock options exercisable.

12. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities may be retired earlier due to mandatory repayments.

($000)	2016	2017	2018	2019	2020	Thereafter
Long-term debt(1)	$ 17,992	$ 17,992	$ 17,992	$ 17,992	$ 1,655,956	$ 3,529,200
Interest on long-term debt(1)	299,394	298,720	298,044	297,370	250,480	475,966
Decommissioning obligation(2)	1,468	2,180	2,420	2,420	2,420	805,469
Transportation and storage(3)	177,466	193,494	207,276	198,024	239,117	3,314,727
Office lease rentals(4)	15,890	34,215	32,794	32,823	33,713	268,440
Diluent purchases(5)	128,864	28,321	21,217	21,217	21,275	60,105
Other commitments(6)	36,100	14,060	5,887	10,162	10,069	76,759
Total	**$ 677,174**	**$ 588,982**	**$ 585,630**	**$ 580,008**	**$ 2,213,030**	**$ 8,530,666**

(1) *This represents the scheduled principal repayments of the senior secured credit facility and the senior unsecured notes and associated interest payments based on interest and foreign exchange rates in effect on December 31, 2015.*

(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 2016 to 2040, including various pipeline commitments which are awaiting regulatory approval.*

(4) *This represents the future commitments for the Calgary Corporate office.*

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

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

13. NON-GAAP MEASURES

Certain financial measures in this MD&A including: net marketing activity, cash flow from operations, operating earnings (loss) and operating cash flow 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 related marketing and storage arrangements. Petroleum sales – third party is disclosed in Note 16 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 (Loss) and Comprehensive Income (Loss).

Cash Flow from Operations

Cash flow from operations is a non-GAAP measure utilized by the Corporation to analyze operating performance and liquidity. Cash flow from operations excludes the net change in non-cash operating working capital, contract cancellation expense, payments on onerous contracts and decommissioning expenditures while the IFRS measurement "Net cash provided by (used in) operating activities" includes these items. Cash flow from operations is reconciled to Net cash provided by (used in) operating activities in the table below.

($000)	2015	2014
Net cash provided by operating activities	**$ 112,158**	$ 767,500
Add (deduct):		
Net change in non-cash operating working capital items	**(77,991)**	5,610
Contract cancellation expense	**12,879**	16,455
Payments on onerous contracts	**541**	–
Decommissioning expenditures	**1,873**	1,893
Cash flow from operations	**$ 49,460**	$ 791,458

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 gains (losses) on disposition of assets, unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial liabilities, unrealized fair value gains and losses on other assets, onerous contracts, contract cancellation expense and the respective deferred tax impact of these adjustments. Operating earnings (loss) is reconciled to "Net loss", the nearest IFRS measure, in the table below.

($000)	2015	2014
Net loss	**$ (1,169,671)**	$ (105,538)
Add (deduct):		
Gain on disposition of assets (1)	**(68,192)**	–
Unrealized net loss on foreign exchange(2)	**785,310**	333,149
Unrealized gain on derivative financial liabilities(3)	**(13,289)**	(1,469)
Unrealized fair value gain on other assets	**–**	(429)
Onerous contracts (4)	**58,719**	–
Contract cancellation expense (5)	**12,879**	16,455
Deferred tax expense relating to these adjustments	**19,870**	5,185
Operating earnings (loss)	**$ (374,374)**	$ 247,353

(1) A gain related to the sale of a non-core undeveloped oil sands asset in the fourth quarter of 2015.

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

(3) 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.

(4) During the fourth quarter of 2015, expenses relating to certain onerous Calgary office building leases were recognized.

(5) For the year ended December 31, 2015, the Corporation recognized contract cancellation expense of $12.9 million primarily related to the termination of a marketing transportation contract, partially offset by a recovery recorded in the second quarter of 2015. During the fourth quarter of 2014, field asset construction contract cancellation expense was recognized as a result of the reduction of the Corporation's capital program.

Operating Cash Flow

Operating cash flow is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of the Corporation's efficiency and its ability to fund future capital investments. Operating cash flow is calculated by deducting the related diluent, transportation, field operating costs and royalties from proprietary production revenues and power revenue. The per-unit calculation of operating cash flow, defined as cash operating netback, is calculated by deducting the related diluent, transportation, operating expenses and royalties from proprietary sales volumes and power revenues, on a per barrel basis.

14. 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

Amounts recorded for stock-based compensation expense are based on several assumptions including the risk-free interest rate, the forfeiture rate, the expected volatility of the Corporation's share price and those of similar publicly listed enterprises, which may not be indicative of future volatility. Accordingly, those amounts 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.

15. TRANSACTIONS WITH RELATED PARTIES

During the year ended December 31, 2015, the Corporation paid $0.3 million in costs on behalf of WP Lexington Private Equity B.V. ("WP Lex"). WP Lex is considered to be a related party of the Corporation as two managing directors of WP Lex also hold positions as members of the Board of Directors of the Corporation.

The only other related party transactions during the year ended December 31, 2015 and December 31, 2014, was the compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($000)	**2015**	**2014**
Salaries and short-term employee benefits	**$ 8,710**	$ 9,975
Share-based compensation expense	**13,323**	13,539
	$ 22,033	$ 23,514

16. OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2015 and December 31, 2014 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, 2015 and December 31, 2014.

17. NEW ACCOUNTING STANDARDS

There were no new accounting standards adopted during the year ended December 31, 2015.

Accounting standards issued but not yet applied

IFRS 9, Financial Instruments, is intended to replace IAS 39, Financial Instruments: Recognition and Measurement and 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. For financial liabilities designated at fair value through profit or loss, a corporation can recognize the portion of the change in fair value related to the change in the corporation's own credit risk through other comprehensive income rather than net earnings. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39, and incorporates new hedge accounting requirements. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The Corporation is currently assessing the impact of the adoption of IFRS 9 on the Corporation's consolidated financial statements.

IFRS 15, Revenue From Contracts With Customers, provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework that applies to contracts with customers. The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Corporation is currently assessing the impact of the adoption of IFRS 15 on the Corporation's consolidated financial statements.

IFRS 16, Leases, will replace IAS 17, Leases. Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. The new standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted. The Corporation is currently assessing the impact of the adoption of IFRS 16 on the Corporation's consolidated financial statements.

18. 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 the risks which have been categorized below as construction risks, operations risks and project development risks. Further information regarding the risk factors which may affect the Corporation is contained in the 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.

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, 2015 and a preparation date of January 29, 2016 ("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 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, which currently deal only with reporting. 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

The Corporation is 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. Recent amendments to the SGER have increased the maximum emission intensity reduction requirement for facility owners from 12% to 15% in 2016 and to 20% starting in 2017. Additionally, one of the options for complying with the SGER is for facility owners to purchase technology fund credits. The recent SGER amendments have increased the price for such credits from $15 per tonne to $20 per tonne for 2016 and to $30 per tonne beginning in 2017.

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 (the "Report") that it commissioned from the Climate Change Advisory Panel and on which the Plan is based. The Plan highlights four key strategies that the government of Alberta will implement to address climate change: (1) the complete phase-out of coal-fired sources of electricity by 2030; (2) implementing an Alberta economy-wide price on greenhouse gas emissions of $30 per tonne; (3) 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 (4) reducing methane emissions from oil and gas activities by 45% by 2025. Details regarding how the Plan will be implemented have not been released, but the Report notes that carbon pricing will be central to the new strategy.

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 early 2016.

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 conventional oil, natural gas and 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. The modernized royalty framework retains the current structure and royalty rates for oil sands and increases the transparency of allowable costs.

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.

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, if successful, could have an adverse effect on MEG and the Christina Lake Project and MEG's other projects.

19. 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. Such officers 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 the financial year end of the Corporation for the foregoing purposes.

20. 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. Management's evaluation concluded that internal controls over financial reporting were effective as of December 31, 2015.

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.

21. 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; the anticipated reductions in operating costs as a result of optimization and scalability of certain operations; and the 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, plans for and results of drilling activity, environmental matters, 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, the securing of adequate supplies and access to markets and transportation infrastructure; the availability of capacity on the electricity transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and revenues; health, safety and environmental risks; 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; and the operational risks and delays in the development, exploration, production, and the capacities and performance associated with MEG's projects.

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.

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, cash flow from operations, operating earnings (loss) and operating cash flow. 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.

22. 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.

23. QUARTERLY SUMMARIES

	2015				2014			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL ($000 unless specified)								
Net earnings (loss)(1)	**(297,275)**	**(427,503)**	**63,414**	**(508,307)**	(150,076)	(100,975)	248,954	(103,441)
Per share, diluted	**(1.32)**	**(1.90)**	**0.28**	**(2.27)**	(0.67)	(0.45)	1.11	(0.46)
Operating earnings (loss)	**(140,234)**	**(86,769)**	**(22,950)**	**(124,421)**	8,084	87,471	111,139	40,659
Per share, diluted	**(0.62)**	**(0.39)**	**(0.10)**	**(0.56)**	0.04	0.39	0.49	0.18
Cash flow from (used in) operations	**(44,130)**	**23,877**	**99,243**	**(29,534)**	134,099	238,659	261,713	156,987
Per share, diluted	**(0.20)**	**0.11**	**0.44**	**(0.13)**	0.60	1.06	1.16	0.70
Cash capital investment	**54,473**	**32,139**	**90,465**	**80,101**	323,970	291,309	298,727	323,533
Cash and cash equivalents	**408,213**	**350,736**	**438,238**	**470,778**	656,097	776,522	839,870	890,335
Working capital	**363,038**	**366,725**	**374,766**	**386,130**	525,534	747,928	805,742	877,069
Long-term debt	**5,190,363**	**5,023,976**	**4,677,577**	**4,759,102**	4,350,421	4,202,966	4,002,378	4,147,840
Shareholders' equity	**3,677,867**	**3,956,689**	**4,358,078**	**4,279,873**	4,768,235	4,894,444	4,970,144	4,705,966
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**42.18**	**46.43**	**57.94**	**48.63**	73.15	97.16	102.99	98.68
C$ equivalent of 1US$ - average	**1.3353**	**1.3093**	**1.2294**	**1.2411**	1.1357	1.0893	1.0905	1.1035
Differential – WTI:WCS ($/bbl)	**19.35**	**17.50**	**14.25**	**18.22**	16.34	22.02	21.87	25.48
Differential – WTI:WCS (%)	**34.4%**	**28.8%**	**20.0%**	**30.2%**	19.7%	20.8%	19.5%	23.4%
Natural gas – AECO ($/mcf)	**2.57**	**2.89**	**2.64**	**2.74**	3.58	4.00	4.70	5.69
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**83,514**	**82,768**	**71,376**	**82,398**	80,349	76,471	68,984	58,643
Bitumen sales – bbls/d	**82,282**	**84,651**	**71,401**	**85,519**	70,116	69,757	70,849	58,089
Steam to oil ratio (SOR)	**2.5**	**2.5**	**2.3**	**2.6**	2.5	2.5	2.4	2.5
Bitumen realization	**23.17**	**31.03**	**44.54**	**25.82**	50.48	65.12	72.75	62.28
Transportation – net	**(5.35)**	**(4.64)**	**(4.57)**	**(4.70)**	(1.82)	(1.09)	(1.80)	(0.67)
Royalties	**(0.25)**	**(0.88)**	**(0.90)**	**(0.80)**	(2.97)	(5.02)	(5.01)	(4.47)
Operating costs – non-energy	**(5.66)**	**(5.98)**	**(7.01)**	**(7.57)**	(6.42)	(7.16)	(9.64)	(9.05)
Operating costs – energy	**(3.58)**	**(3.97)**	**(3.71)**	**(4.07)**	(5.16)	(5.58)	(6.45)	(8.43)
Power revenue	**0.72**	**0.85**	**1.29**	**1.15**	1.45	2.43	1.60	3.85
Cash operating netback	**9.05**	**16.41**	**29.64**	**9.83**	35.56	48.70	51.45	43.51
Power sales price (C$/MWh)	**19.67**	**25.09**	**39.55**	**28.21**	31.67	59.07	40.98	62.26
Power sales (MW/h)	**125**	**119**	**97**	**145**	134	119	115	150
Depletion and depreciation rate per bbl of production	**16.55**	**15.99**	**15.84**	**15.58**	13.63	13.92	15.71	15.39
COMMON SHARES								
Shares outstanding, end of period (000)	**224,997**	**224,942**	**224,881**	**223,847**	223,847	223,794	223,673	222,575
Volume traded (000)	**76,631**	**73,099**	**40,929**	**57,657**	94,588	30,649	70,199	32,102
Common share price ($)								
High	**13.15**	**20.36**	**25.20**	**24.31**	34.69	40.75	41.29	37.84
Low	**7.33**	**7.87**	**17.56**	**14.84**	13.30	34.00	35.52	29.41
Close (end of period)	**8.02**	**8.24**	**20.40**	**20.46**	19.55	34.38	38.89	37.36

(1) Includes net unrealized foreign exchange gains and losses on translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.

24. ANNUAL SUMMARIES

	2015	2014	2013	2012	2011
Unaudited					
FINANCIAL ($000 unless specified)					
Net earnings (loss)[1]	**(1,169,671)**	(105,538)	(166,405)	52,569	63,837
Per share, diluted	**(5.21)**	(0.47)	(0.75)	0.26	0.32
Operating earnings (loss)	**(374,374)**	247,353	386	21,242	109,255
Per share, diluted	**(1.67)**	1.10	0.00	0.11	0.55
Cash flow from (used in) operations	**49,460**	791,458	253,424	212,514	304,627
Per share, diluted	**0.22**	3.52	1.13	1.06	1.54
Cash capital investment[2]	**257,178**	1,237,539	2,111,824	1,567,906	914,292
Cash and cash equivalents	**408,213**	656,097	1,179,072	1,474,843	1,495,131
Working capital	**363,038**	525,534	1,045,606	1,655,915	1,475,245
Long-term debt	**5,190,363**	4,350,421	3,990,748	2,478,660	1,741,394
Shareholders' equity	**3,677,867**	4,768,235	4,788,430	4,870,534	3,984,104
BUSINESS ENVIRONMENT					
WTI (US$/bbl)	**48.80**	93.00	97.96	94.21	95.12
C$ equivalent of 1US$ - average	**1.2788**	1.1047	1.0296	0.9994	0.9893
Differential – WTI:WCS ($/bbl)	**17.29**	21.63	25.89	21.01	16.95
Differential – WTI:WCS (%)	**27.7%**	21.1%	25.7%	22.3%	18.0%
Natural gas – AECO ($/mcf)	**2.71**	4.50	3.16	2.38	3.66
OPERATIONAL ($/bbl unless specified)					
Bitumen production – bbls/d	**80,025**	71,186	35,317	28,773	26,605
Bitumen sales – bbls/d	**80,965**	67,243	33,715	28,845	26,587
Steam to oil ratio (SOR)	**2.5**	2.5	2.6	2.4	2.4
Bitumen realization	**30.63**	62.67	49.28	46.93	58.74
Transportation – net	**(4.82)**	(1.38)	(0.26)	(0.31)	(1.39)
Royalties	**(0.70)**	(4.36)	(3.14)	(2.46)	(3.24)
Operating costs – non-energy	**(6.54)**	(8.02)	(9.00)	(9.71)	(10.32)
Operating costs – energy	**(3.84)**	(6.30)	(4.62)	(3.46)	(5.14)
Power revenue	**0.99**	2.26	3.61	3.19	4.50
Cash operating netback	**15.72**	44.87	35.87	34.18	43.15
Power sales price (C$/MWh)	**27.48**	48.83	76.23	59.22	74.33
Power sales (MW/h)	**121**	129	67	65	67
Depletion and depreciation rate per bbl of production	**16.00**	14.57	14.67	13.76	12.80
COMMON SHARES					
Shares outstanding, end of period (000)	**224,997**	223,847	222,507	220,190	193,472
Volume traded (000)	**248,316**	227,538	134,087	73,738	105,783
Common share price ($)					
High	**25.20**	41.29	36.69	47.11	52.90
Low	**7.33**	13.30	25.50	30.25	32.26
Close (end of period)	**8.02**	19.55	30.61	30.44	41.57

(1) *Includes net unrealized foreign exchange gains and losses on translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.*

(2) *Defined as total capital investment excluding dispositions, capitalized interest and non-cash items.*

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 prepared 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 our internal controls over financial reporting were effective as of December 31, 2015.

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, 2015. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

W. J. McCaffrey

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

Eric L. Toews, CA
Chief Financial Officer

March 3, 2016

Independent Auditor's Report

TO THE SHAREHOLDERS OF MEG ENERGY CORP.

We have audited the accompanying consolidated financial statements of MEG Energy Corp., which comprise the consolidated balance sheet as at December 31, 2015 and December 31, 2014 and the consolidated statements of earnings (loss) 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 as issued by the International Accounting Standards Board, 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. as at December 31, 2015 and December 31, 2014 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

March 3, 2016

CONSOLIDATED BALANCE SHEET

(Expressed in thousands of Canadian dollars)

As at December 31	Note	2015	2014
Assets			
Current assets			
Cash and cash equivalents	24	**$ 408,213**	$ 656,097
Trade receivables and other	5	**150,042**	177,219
Inventories	6	**53,079**	153,320
		611,334	986,636
Non-current assets			
Property, plant and equipment, net	7	**8,011,760**	8,195,490
Exploration and evaluation assets	8	**546,421**	588,526
Other intangible assets, net	9	**84,142**	83,090
Other assets	10	**146,612**	76,366
Total assets		**$ 9,400,269**	$ 9,930,108
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	11	**$ 217,991**	$ 427,910
Current portion of long-term debt	12	**17,992**	15,081
Current portion of provisions and other liabilities	13	**12,313**	18,111
		248,296	461,102
Non-current liabilities			
Long-term debt	12	**5,190,363**	4,350,421
Provisions and other liabilities	13	**196,274**	172,154
Deferred income tax liability	14	**87,469**	178,196
Total liabilities		**5,722,402**	5,161,873
Shareholders' equity			
Share capital	15	**4,836,800**	4,797,853
Contributed surplus	15	**171,835**	153,837
Deficit		**(1,366,341)**	(196,670)
Accumulated other comprehensive income		**35,573**	13,215
Total shareholders' equity		**3,677,867**	4,768,235
Total liabilities and shareholders' equity		**$ 9,400,269**	$ 9,930,108

Commitments and contingencies (note 29), Subsequent event (note 31)
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 3, 2016.

W. J. 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	2015	2014
Petroleum revenue, net of royalties	16	**$ 1,882,853**	$ 2,743,987
Other revenue	17	**43,063**	85,977
		1,925,916	2,829,964
Diluent and transportation	18	**1,050,377**	1,228,079
Operating expenses	22	**306,725**	351,534
Purchased product and storage		**129,615**	163,387
Depletion and depreciation	7,9	**467,422**	378,544
General and administrative	22	**118,518**	111,366
Stock-based compensation	15	**50,105**	48,310
Research and development		**7,497**	6,003
		2,130,259	2,287,223
Revenues less expenses		**(204,343)**	542,741
Other income (expense)			
Gain on disposition of assets	8	**68,192**	–
Interest and other income		**3,078**	9,107
Foreign exchange loss, net	19	**(801,739)**	(338,629)
Net finance expense	20	**(255,194)**	(196,858)
Other expenses	21	**(71,598)**	(36,123)
		(1,057,261)	(562,503)
Loss before income taxes		**(1,261,604)**	(19,762)
Income tax expense (recovery)	14	**(91,933)**	85,776
Net loss		**(1,169,671)**	(105,538)
Other comprehensive income, net of tax			
Items that may be reclassified to profit or loss:			
Foreign currency translation adjustment		**22,358**	10,332
Comprehensive loss		**$ (1,147,313)**	$ (95,206)
Net loss per common share			
Basic	25	**$ (5.21)**	$ (0.47)
Diluted	25	**$ (5.21)**	$ (0.47)

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, 2014		**$ 4,797,853**	**$ 153,837**	**$ (196,670)**	**$ 13,215**	**$ 4,768,235**
Stock-based compensation	15	**–**	**56,945**	**–**	**–**	**56,945**
RSUs vested and released	15	**38,947**	**(38,947)**	**–**	**–**	**–**
Comprehensive income (loss)		**–**	**–**	**(1,169,671)**	**22,358**	**(1,147,313)**
Balance as at December 31, 2015		**$ 4,836,800**	**$ 171,835**	**$ (1,366,341)**	**$ 35,573**	**$ 3,677,867**
Balance as at December 31, 2013		$ 4,751,374	$ 126,666	$ (92,493)	$ 2,883	$ 4,788,430
Stock options exercised	15	14,665	(3,499)	–	–	11,166
Stock-based compensation	15	–	62,484	–	–	62,484
RSUs vested and released	15	31,814	(31,814)	1,361	–	1,361
Comprehensive income		–	–	(105,538)	10,332	(95,206)
Balance as at December 31, 2014		$ 4,797,853	$ 153,837	$ (196,670)	$ 13,215	$ 4,768,235

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	2015	2014
Cash provided by (used in):			
Operating activities			
Net loss		**$ (1,169,671)**	$ (105,538)
Adjustments for:			
Depletion and depreciation	7,9	**467,422**	378,544
Stock-based compensation	15	**50,105**	48,310
Gain on disposition of asset		**(68,192)**	–
Unrealized loss on foreign exchange	19	**785,310**	333,149
Unrealized gain on derivative financial liabilities	20	**(13,289)**	(1,469)
Onerous contracts	21	**58,719**	–
Inventory write-down	6,21	**–**	19,668
Deferred income tax expense (recovery)	14	**(90,733)**	85,776
Amortization of debt issue costs	10,12	**11,795**	10,566
Other		**5,115**	5,997
Decommissioning expenditures	13	**(1,873)**	(1,893)
Payments on onerous contracts		**(541)**	–
Net change in non-cash working capital items	24	**77,991**	(5,610)
Net cash provided by (used in) operating activities		**112,158**	**767,500**
Investing activities			
Capital investments			
Property, plant and equipment	7	**(305,670)**	(1,282,194)
Exploration and evaluation	8	**(1,458)**	(7,749)
Other intangible assets	9	**(6,498)**	(23,571)
Proceeds on disposition of assets	8	**110,015**	–
Other		**(930)**	4,420
Net change in non-cash working capital items	24	**(212,455)**	(3,346)
Net cash provided by (used in) investing activities		**(416,996)**	**(1,312,440)**
Financing activities			
Repayment of long-term debt		**(17,020)**	(14,467)
Issue of shares		**–**	11,166
Financing costs		**–**	(10,035)
Net cash provided by (used in) financing activities		**(17,020)**	**(13,336)**
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	19	**73,974**	35,301
Change in cash and cash equivalents		**(247,884)**	(522,975)
Cash and cash equivalents, beginning of year	24	**656,097**	1,179,072
Cash and cash equivalents, end of year	24	**$ 408,213**	$ 656,097

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

Notes To Consolidated Financial Statements

Year ended December 31, 2015

(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 is using a staged approach to development. 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 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. The corporate office is located at 520 - 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. These consolidated financial statements were approved by the Corporation's Board of Directors on March 3, 2016.

3. SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis, except for the revaluation of certain financial assets and financial liabilities to fair value, including derivative financial instruments, which are measured at fair value.

(b) Basis 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 accounts for its undivided 50% interest in Access Pipeline as a joint operation. The Corporation's interest in the Access Pipeline is included in the consolidated financial statements in proportion to the Corporation's share of assets, liabilities, revenues and expenses.

(c) Operating segments

The Corporation's operations are aggregated into one operating segment for reporting consistent with the internal reporting provided to the chief operating decision-maker of the Corporation.

(d) 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.

(e) Joint operations

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.

(f) 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 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 as hedges. The Corporation’s investments in U.S. auction rate securities (“ARS”) are classified as fair value through earnings or loss.

Financial instruments in this category 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 presented in earnings or loss within net finance expense 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.

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 due within twelve months from the balance sheet date. Otherwise, they are presented as non-current liabilities.

iv. Derivative financial instruments

The Corporation may use derivative instruments to manage commodity price, foreign currency and interest rate exposures. All derivatives have been classified at fair value through earnings or loss. Derivative financial instruments are included on the balance sheet within provisions and other liabilities and are classified as current or non-current based on the contractual terms specific to the instrument.

Gains and losses on re-measurement of derivatives are included in net earnings (loss) in the period in which they arise.

(g) 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 commercial paper, money market deposits or similar instruments, with a maturity of 90 days or less.

(h) Short-term investments

Short-term investments consist of commercial paper, money market deposits or similar instruments with a maturity of between 91 and 365 days.

(i) Trade receivables and other

Trade receivables are recorded based on the Corporation's revenue recognition policy as described in note 3(t). If applicable, an allowance for doubtful accounts is recorded to provide for specific doubtful receivables. 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 venture partners.

(j) Inventories

Product inventories consist of crude oil products and are valued at the lower of cost and net realizable value on a weighted average cost basis. Costs include direct and indirect expenditures incurred 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.

(k) Property, plant and equipment and exploration and evaluation assets

i. Recognition and measurement

Exploration and evaluation ("E&E") expenditures, including the costs of acquiring licenses and directly attributable general and administrative costs, initially are capitalized as exploration and evaluation assets. The costs are accumulated in cost centres pending determination of technical feasibility and commercial viability. 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. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units ("CGU's").

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. A review of each project area is carried out, at least annually, to ascertain whether proved or probable reserves have been discovered. Upon determination of proved or probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to property, plant and equipment. If it is determined that an E&E 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.

Development and production items of property, plant and equipment, which include oil sands development, production, transportation and storage assets are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development, production, transportation and storage assets are grouped into CGU's for impairment testing. 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. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components).

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. All other borrowing costs are recognized over the term of the related debt facility as an expense using the effective interest method. The Corporation capitalizes overhead and administrative expenses that are directly attributable to bringing qualifying assets into operation. The capitalization of borrowing costs and overhead and administrative expenses 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.

ii. Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as crude oil, transportation and storage assets only when it is probable that future economic benefits associated with the item will flow to the Corporation and the cost of the item can be measured reliably. Such capitalized crude oil, transportation and storage assets generally represent costs incurred in developing proved and/or probable reserves and enhancing production from such reserves. All other expenditures are recognized in earnings or loss as incurred.

iii. Depletion and depreciation

The net carrying value of field production assets are depleted using the unit-of-production method by reference to the ratio of production in the year to the related proved reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

The net carrying value of major facilities and equipment are depreciated on a unit-of-production basis over the total productive capacity of the facilities. Where significant components of development or production assets have different useful lives, they are accounted for and depreciated as separate items of property, plant and equipment.

The costs of planned major inspections, overhaul and turnaround activities that maintain property, plant and equipment 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 outside of major inspection, overhaul or turnaround activities are capitalized when it is probable that future economic benefits will flow to the Corporation.

The net carrying values of transportation and storage equipment are depreciated on a straight-line basis over their estimated fifty year useful lives.

Corporate assets consist primarily of office equipment and leasehold improvements and are stated at cost less accumulated depreciation. 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.

Assets under construction are not subject to depletion and depreciation.

(l) Other intangible assets

Other 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 other 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.

(m) Other assets – long-term pipeline linefill

The Corporation has entered into agreements to transport 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 property, plant and equipment. 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.

(n) Leased assets

Leases where the Corporation assumes substantially all the risks and rewards of ownership are classified as finance leases. 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. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term to produce a constant periodic rate of interest on the remaining balance of the liability.

All other leases are operating leases, which are not recognized on the Corporation's balance sheet. Payments made under operating leases are recognized as an expense as incurred over the term of the lease.

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.

(o) 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.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All 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. For financial assets measured at amortized cost, the reversal is recognized in earnings or loss.

ii. Non-financial assets

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. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, as crude oil assets, 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 CGU's. The recoverable amount of a CGU is the greater of its value in use and its fair value less costs of disposal. E&E assets are assessed for impairment within the aggregation of all CGU's 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 in earnings or loss. Impairment losses recognized in respect of CGU's 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.

(p) 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 determined by discounting the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

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.

The decommissioning provision is measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the decommissioning provision is 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. Increases in the decommissioning provision due to the passage of time are recognized as a 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 provision is measured at the present value of the estimated future cash flows associated with the contract. Subsequent to the initial measurement, the provision is 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. The net amount of actual costs incurred and sublease recoveries earned are charged against the onerous contract provision.

(q) Deferred 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 on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

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.

(r) Share capital

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

(s) Share based payments

The Corporation's Stock Option Plan and Restricted Share Unit Plan each allow for the granting of stock options and restricted share units ("RSUs"), including performance share units ("PSUs") to directors, officers, employees and consultants. The grant date fair value of stock options, RSUs and PSUs granted is recognized as stock-based compensation expense, with a corresponding increase in contributed surplus, over the vesting period of the options, RSUs and PSUs, respectively. 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 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 RSU Plan and, as such, the RSUs and PSUs are accounted for within shareholders' equity.

The Corporation's Deferred Share Unit Plan allows for the granting of 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 a compensation expense on the grant date and future fluctuations in the fair value are recognized as a compensation expense in the period in which they occur.

(t) Revenues

i. Petroleum revenue and royalty recognition:

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

ii. Other revenue recognition:

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.

(u) 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.

(v) 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.

(w) Net finance expense

Net finance expense is comprised of interest expense on borrowings, accretion of the discount on provisions, and gains and losses on derivative financial instruments and other assets.

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.

(x) 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 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.

(y) New accounting standards adopted during the year

There were no new accounting standards adopted during the year ended December 31, 2015.

(z) Accounting standards issued but not yet applied

The IASB has issued the following standards which have not yet been adopted by the Corporation: IFRS 9, Financial Instruments; IAS 15, Revenue From Contracts With Customers, and IFRS 16, Leases. The Corporation is currently assessing the impact of the adoption of these standards on the Corporation's consolidated financial statements.

The following is a brief summary of the new and amended standards:

IFRS 9, Financial Instruments, is intended to replace IAS 39, Financial Instruments: Recognition and Measurement and 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. For financial liabilities designated at fair value through profit or loss, a corporation can recognize the portion of the change in fair value related to the change in the corporation's own credit risk through other comprehensive income rather than net earnings. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39, and incorporates new hedge accounting requirements. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted.

IFRS 15, Revenue From Contracts With Customers, provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework that applies to contracts with customers. The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted.

IFRS 16, Leases, will replace IAS 17, Leases. Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. The new standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted.

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 property, plant and equipment 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, transportation and storage equipment are based on management's best estimate of their useful lives. 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 property, plant and equipment 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, based on current economic factors which management believes are reasonable, have been made to estimate the future liability. 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 contracts 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

Amounts recorded for stock-based compensation expense are based on several assumptions including the risk-free interest rate, the forfeiture rate, the expected volatility of the Corporation's share price and those of similar publicly listed enterprises, which may not be indicative of future volatility. Accordingly, those amounts 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.

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.

(i) Derivative financial instruments

The estimated fair values of financial assets and liabilities, by their very nature, 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 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	2015	2014
Trade receivables	**$ 130,187**	$ 167,559
Deposits and advances	**15,491**	5,344
Current portion of deferred financing costs	**4,364**	4,316
	$ 150,042	$ 177,219

6. INVENTORIES

As at December 31	2015	2014
Diluent	**$ 18,157**	$ 83,001
Bitumen blend	**32,669**	68,273
Materials and supplies	**2,253**	2,046
	$ 53,079	$ 153,320

During the year ended December 31, 2015, a total of $0.9 billion (2014 - $1.2 billion) in inventory product costs were charged to earnings through diluent and transportation expense.

During the year ended December 31, 2014, the Corporation recognized a $19.7 million bitumen blend inventory write-down to net realizable value as a result of a decline in global crude oil prices.

7. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Corporate assets	Total
Cost				
Balance as at December 31, 2013	$ 6,493,665	$ 1,276,447	$ 41,035	$ 7,811,147
Additions	1,002,619	295,568	6,082	1,304,269
Change in decommissioning liabilities	43,085	680	–	43,765
Transfer to other assets (note 7)	–	(12,381)	–	(12,381)
Balance as at December 31, 2014	7,539,369	1,560,314	47,117	9,146,800
Additions	254,586	54,515	3,959	313,060
Change in decommissioning liabilities	(25,711)	(2,344)	–	(28,055)
Transfer to other assets (note 7)	–	(6,938)	–	(6,938)
Balance as at December 31, 2015	**$ 7,768,244**	**$ 1,605,547**	**$ 51,076**	**$ 9,424,867**
Accumulated depletion and depreciation				
Balance as at December 31, 2013	$ 513,422	$ 31,452	$ 11,322	$ 556,196
Depletion and depreciation for the year	370,301	19,661	5,152	395,114
Balance as at December 31, 2014	883,723	51,113	16,474	951,310
Depletion and depreciation for the year	426,946	29,227	5,624	461,797
Balance as at December 31, 2015	**$ 1,310,669**	**$ 80,340**	**$ 22,098**	**$ 1,413,107**
Carrying amounts				
Balance as at December 31, 2014	$ 6,655,646	$ 1,509,201	$ 30,643	$ 8,195,490
Balance as at December 31, 2015	**$ 6,457,575**	**$ 1,525,207**	**$ 28,978**	**$ 8,011,760**

During the year ended December 31, 2015, the Corporation capitalized $56.4 million of interest and finance charges related to the development of capital projects (year ended December 31, 2014 - $74.7 million). As at December 31, 2015, $663.8 million of assets under construction were included within property, plant and equipment (December 31, 2014 - $749.1 million). Assets under construction are not subject to depletion and depreciation. As of December 31, 2015, no impairment has been recognized on these assets as the net present value of future cash flows exceeded the carrying value of the respective CGUs.

8. EXPLORATION AND EVALUATION ASSETS

Cost	
Balance as at December 31, 2013	$ 579,497
Additions	7,749
Change in decommissioning liabilities	1,280
Balance as at December 31, 2014	**$ 588,526**
Additions	1,458
Dispositions	(41,827)
Change in decommissioning liabilities	(1,736)
Balance as at December 31, 2015	**$ 546,421**

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. As at December 31, 2015, these assets were assessed for impairment within the aggregation of all of the Corporation's CGUs and no impairment was recognized. During the year ended December 31, 2015, the Corporation did not capitalize any interest and finance charges related to exploration and evaluation assets (year ended December 31, 2014 - $1.3 million).

In the fourth quarter of 2015, the Corporation completed a sale of a non-core undeveloped oil sands asset to an unrelated third party for gross proceeds of $110.0 million, resulting in a gain of $68.2 million.

9. OTHER INTANGIBLE ASSETS

Cost	
Balance as at December 31, 2013	$ 66,209
Additions	23,571
Balance as at December 31, 2014	$ 89,780
Additions	6,498
Balance as at December 31, 2015	**$ 96,278**

Accumulated depreciation	
Balance as at December 31, 2013	$ 3,004
Depreciation for the year	3,686
Balance as at December 31, 2014	$ 6,690
Depreciation for the year	5,446
Balance as at December 31, 2015	**$ 12,136**

Carrying Amounts	
As at December 31, 2014	$ 83,090
As at December 31, 2015	**$ 84,142**

As at December 31, 2015, other intangible assets include $63.6 million invested to maintain the right to participate in a potential pipeline project and $20.5 million invested in software that is not an integral component of the related computer hardware (December 31, 2014 - $60.2 million and $22.9 million, respectively). As of December 31, 2015, no impairment has been recognized on these assets.

10. OTHER ASSETS

As at December 31	2015	2014
Long-term pipeline linefill[(a)]	**$ 131,141**	$ 56,900
ARS[(b)]	**3,470**	2,908
Deferred financing costs[(c)]	**16,366**	20,874
	150,977	80,682
Less current portion of deferred financing costs	**(4,365)**	(4,316)
	$ 146,612	$ 76,366

(a) The Corporation has entered into agreements to transport diluent and bitumen blend on third-party owned pipelines and is required to supply linefill for these pipelines. As these pipelines are owned by third parties, the linefill is not considered to be a component of the Corporation's property, plant and equipment. During the year ended December 31, 2015, the Corporation transferred $6.9 million of bitumen blend from property, plant and equipment to long-term pipeline linefill (year ended December 31, 2014 - $12.4 million). In addition, $40.7 million of diluent and $11.5 million of bitumen blend was transferred from inventories to long-term pipeline linefill to meet these linefill obligations (year ended December 31, 2014 - nil). The linefill is classified as a long-term asset as these transportation contracts extend beyond the year 2024. As of December 31, 2015, no impairment has been recognized on these assets.

(b) The investment in ARS is considered a long-term asset and is recorded at its fair value based on quoted prices in an inactive market from a third-party independent broker (note 26(a)). Changes in fair value are included in net finance expense in the period in which they arise.

(c) Costs associated with establishing the Corporation's revolving credit facility are deferred and amortized over the term of the credit facility.

11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31	2015	2014
Trade payables	**$ 2,576**	$ 4,313
Accrued and other liabilities	**141,331**	362,061
Interest payable	**74,084**	61,536
	$ 217,991	$ 427,910

12. LONG-TERM DEBT

As at December 31	2015	2014
Senior secured term loan (December 31, 2015 - US$1.249 billion; December 31, 2014 - US$1.262 billion[a]	**$ 1,727,924**	$ 1,463,466
6.5% senior unsecured notes (US$750 million)[b]	**1,038,000**	870,075
6.375% senior unsecured notes (US$800 million)[c]	**1,107,200**	928,080
7.0% senior unsecured notes (US$1.0 billion)[d]	**1,384,000**	1,160,100
	5,257,124	4,421,721
Less current portion of senior secured term loan	**(17,992)**	(15,081)
Less unamortized financial derivative liability discount	**(14,377)**	(17,514)
Less unamortized deferred debt issue costs	**(34,392)**	(38,705)
	$ 5,190,363	$ 4,350,421

(a) The senior secured credit facilities are comprised of a US$1.249 billion term loan and a US$2.5 billion revolving credit facility. The senior secured credit facilities are secured by substantially all the assets of the Corporation. The term loan bears a floating interest rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 175 or 275 basis points, respectively. The term loan also has an interest rate floor of 200 basis points based on U.S. Prime or 100 basis points based on LIBOR. The term loan is to be repaid in quarterly installment payments equal to US$3.25 million, with the balance due on March 31, 2020.

Effective December 15, 2014, the Corporation entered into a five-year US$500.0 million guaranteed letter of credit facility guaranteed by Export Development Canada. The facility matures on November 5, 2019. Letters of credit issued under this facility do not consume capacity of the revolving credit facility. As at December 31, 2015, letters of credit of US$179.2 million had been issued under this facility.

(b) Effective March 18, 2011, the Corporation issued US$750.0 million in aggregate principal amount of 6.5% Senior Unsecured Notes, with a maturity date of March 15, 2021. Interest is paid semi-annually on March 15 and September 15. No principal payments are required until March 15, 2021.

(c) 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.

(d) 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.

The U.S. dollar denominated debt was translated into Canadian dollars at the year-end exchange rate of US$1 = C$1.3840 (December 31, 2014 – US$1 = C$1.1601).

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. The first maturity of any of the Corporation's long-term debt obligations is March 2020.

	2016	2017	2018	2019	2020	Thereafter
Required debt principal repayments	$17,992	$17,992	$17,992	$17,992	$1,655,956	$3,529,200

13. PROVISIONS AND OTHER LIABILITIES

As at December 31	2015	2014
Decommissioning provision[(a)]	**$ 130,381**	$ 156,382
Onerous contracts[(b)]	**58,178**	–
Derivative financial liabilities[(c)]	**16,223**	29,511
Deferred lease inducements	**3,805**	4,372
Provisions and other liabilities	**208,587**	190,265
Less current portion	**(12,313)**	(18,111)
Non-current portion	**$ 196,274**	$ 172,154

(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	2015	2014
Decommissioning provision, beginning of year	**$ 156,382**	$ 108,695
Changes in estimated future cash flows	**14,076**	20,406
Changes in discount rates	**(48,933)**	13,798
Liabilities incurred	**5,066**	10,841
Liabilities settled	**(1,873)**	(1,893)
Accretion	**5,663**	4,535
Balance, end of year	**130,381**	156,382
Less current portion	**(1,485)**	(1,835)
Non-current portion	**$ 128,896**	$ 154,547

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 $816.4 million (December 31, 2014 - $707.8 million). The Corporation has estimated the net present value of the decommissioning obligations using a credit-adjusted risk-free rate of 8.3% (December 31, 2014 – 6.0%).

As at December 31, 2015, a 1% increase in the credit-adjusted risk-free rate would result in an $11.3 million decrease in the present value of the decommissioning provision. The decommissioning provision is estimated to be settled in periods up to the year 2064.

(b) Onerous contracts

As at December 31, 2015, the Corporation had recognized a total provision of $58.2 million related to certain onerous Calgary office lease contracts (December 31, 2014 - nil). The provision represents the present value of the difference between the minimum future lease payments that the Corporation is obligated to make under the non-cancellable onerous operating lease contracts and estimated sublease recoveries. The total undiscounted amount of estimated future cash flows to settle the obligations is $60.9 million. These cashflows have been discounted using a risk-free discount rate of 1.0%. This estimate may vary as a result of changes in estimated sublease recoveries. The onerous contract provision is estimated to be settled in periods up to the year 2031.

(c) Derivative financial liabilities

As at December 31	2015	2014
1% interest rate floor	**$ 11,740**	$ 20,844
Interest rate swaps	**4,483**	8,667
Derivative financial liabilities	**16,223**	29,511
Less current portion	**(8,316)**	(15,538)
Non-current portion	**$ 7,907**	$ 13,973

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. As a result, the interest rate floor derivative is required to be separated from the carrying value of long-term debt and accounted for as a separate derivative financial liability measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

The Corporation is exposed to interest rate risk in relation to interest income earned on cash and cash equivalents and in relation to interest expense on floating rate long-term debt. To mitigate a portion of the risk of interest rate increases on long-term debt, the Corporation periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. As at December 31, 2015, the Corporation had entered into interest rate swaps on US$748.0 million (note 26[b]) and these interest rate swap contracts expire on September 30, 2016. Interest rate swaps are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

14. INCOME TAXES

The income tax provisions differ from results which would be obtained had the Corporation applied the combined federal and provincial statutory rates of 26% (2014 – 25%) to earnings or loss before income taxes. The reasons for these differences are as follows:

For the years ended December 31	2015	2014
Expected income tax recovery	**$ (328,017)**	$ (4,940)
Add (deduct) the tax effect of:		
Stock-based compensation	**13,027**	12,077
Non-taxable loss on foreign exchange	**110,815**	46,056
Taxable capital losses not recognized	**110,815**	46,056
Tax benefit of vested RSUs	**(5,507)**	(13,783)
Rate change	**14,350**	–
Rate variance	**(3,908)**	–
Scientific research and experimental development input tax credits	**(3,622)**	–
Other	**114**	310
	$ (91,933)	$ 85,776
Current income tax expense (recovery)	**$ (1,200)**	$ –
Deferred income tax expense (recovery)	**(90,733)**	85,776
Income tax expense (recovery)	**$ (91,933)**	$ 85,776

During the year ended December 31, 2015, the Corporation recognized a current income tax recovery of $1.2 million relating to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures.

In June 2015, the Government of Alberta enacted an increase in the Alberta corporate income tax rate from 10% to 12%. As a result, the Corporation increased its opening deferred income tax liability by $14.4 million, with a corresponding increase to deferred income tax expense.

The analysis of deferred tax assets and deferred tax liabilities is as follows:

As at December 31	**2015**	**2014**
Deferred tax liabilities:		
Deferred tax liabilities to be recovered after more than 12 months	**$ 1,097,922**	$ 878,888
Deferred tax liabilities to be recovered within 12 months	**–**	–
	1,097,922	878,888
Deferred tax assets:		
Deferred tax assets to be recovered after more than 12 months	**(1,000,382)**	(694,500)
Deferred tax assets to be recovered within 12 months	**(10,071)**	(6,192)
	(1,010,453)	(700,692)
Deferred tax liabilities (net)	**$ 87,469**	$ 178,196

The net movement within the deferred income tax liability is as follows:

	2015	**2014**
Balance as at January 1	**$ 178,196**	$ 93,794
Charged (credited) to earnings (loss)	**(90,733)**	85,776
Charged (credited) to other comprehensive income	**6**	(13)
Tax credited directly to equity	**–**	(1,361)
Balance as at December 31	**$ 87,469**	**$ 178,196**

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

Deferred tax liabilities	**Property, plant and equipment**	**Other**	**Total**
Balance as at December 31, 2013	$ 720,458	$ 4,341	$ 724,799
Charged to earnings (loss)	151,221	2,868	154,089
Balance as at December 31, 2014	$ 871,679	$ 7,209	$ 878,888
Charged to earnings (loss)	215,749	3,285	219,034
Balance as at December 31, 2015	**$ 1,087,428**	**$ 10,494**	**$ 1,097,922**

Deferred tax assets	Tax losses	Derivitive financial liabilities	Provisions	Other	Total
Balance as at December 31, 2013	$ (620,984)	$ (7,745)	$ (491)	$ (1,785)	$ (631,005)
Charged (credited) to earnings (loss)	(63,160)	367	(661)	(4,859)	(68,313)
Credited to other comprehensive income	–	–	–	(13)	(13)
Credited to equity	(1,361)	–	–	–	(1,361)
Balance as at December 31, 2014	$ (685,505)	$ (7,378)	$ (1,152)	$ (6,657)	$ (700,692)
Charged (credited) to the earnings (loss)	(288,160)	2,998	(1,115)	(23,490)	(309,767)
Charged to other comprehensive income	–	–	–	6	6
Balance as at December 31, 2015	**$ (973,665)**	**$ (4,380)**	**$ (2,267)**	**$ (30,141)**	**$ (1,010,453)**

As at December 31, 2015, the Corporation had approximately $7.3 billion in available tax pools (December 31, 2014 - $7.0 billion). Included in the tax pools are $3.6 billion of non-capital loss carry forward balances ($0.2 billion expiring in 2026; $0.2 billion expiring in 2027; $0.3 billion expiring in 2028; $0.5 billion expiring in 2029; $0.3 billion expiring in 2030 and $2.1 billion expiring after 2030). In addition, as at December 31, 2015, the Corporation had an additional $0.6 billion (December 31, 2014 - $0.9 billion) of capital investment in incomplete projects which will serve to increase available tax pools upon completion of the projects. As at December 31, 2015 the Corporation had not recognized the tax benefit related to $0.7 billion of unrealized taxable capital foreign exchange losses (December 31, 2014 - $0.3 billion).

15. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

(b) Changes in issued common shares are as follows:

	2015		2014	
	Number of shares	**Amount**	**Number of shares**	**Amount**
Balance, beginning of year	**223,846,891**	**$ 4,797,853**	222,506,896	$ 4,751,374
Issued upon exercise of stock options	**–**	**–**	412,644	14,665
Issued upon vesting and release of RSUs	**1,150,098**	**38,947**	927,351	31,814
Balance, end of year	**224,996,989**	**$ 4,836,800**	223,846,891	$ 4,797,853

(c) Stock options outstanding:

The Corporation's stock option plan allows for the granting of options to directors, officers, employees and consultants of the Corporation. Options granted are generally fully exercisable by the third anniversary of the grant date and expire seven years after the grant date.

	2015		2014	
	Stock options	**Weighted average exercise price**	**Stock options**	**Weighted average exercise price**
Outstanding, beginning of year	**7,865,788**	**$ 34.87**	8,859,028	$ 35.49
Granted	**2,968,798**	**18.55**	1,790,697	37.64
Exercised	**–**	**–**	(412,644)	27.05
Forfeited	**(531,473)**	**31.49**	(332,545)	39.23
Expired	**(377,800)**	**41.00**	(2,038,748)	40.88
Outstanding, end of year	**9,925,313**	**$ 29.94**	7,865,788	$ 34.87

As at December 31, 2015						
	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)
$11.01 - $20.00	2,842,047	$ 18.52	6.45	–	$ –	–
$20.01 - $30.00	1,152,240	23.94	0.83	1,111,921	24.01	0.64
$30.01 - $40.00	5,245,457	34.77	4.10	3,634,222	34.38	3.65
$40.01 - $51.43	685,569	50.40	2.47	685,569	50.40	2.47
	9,925,313	**$ 29.94**	**4.28**	**5,431,712**	**$ 34.28**	**2.86**

The fair value of each option granted during the years ended December 31, 2015 and 2014 was estimated on the date of the grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2015	2014
Risk-free rate	**1.01%**	1.55%
Expected lives	**5 years**	5 years
Volatility	**40%**	31%
Annual dividend per share	**$ nil**	$ nil
Fair value of options granted	**$ 6.99**	$ 11.66

(d) Restricted share units and performance share units outstanding:

The Restricted Share Unit Plan allows for the granting of Restricted Share Units ("RSUs"), including Performance Share Units ("PSUs"), to directors, officers, employees and consultants of the Corporation. An RSU, including a PSU, 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. A PSU is an RSU, the vesting of which has been made conditional on the satisfaction of certain performance criteria. PSUs become eligible to vest if the Corporation satisfies the performance criteria identified by the Corporation's Board of Directors within a target range. A pre-determined multiplier is then applied to PSUs that have become eligible to vest, dependent on the point in the target range to which such performance criteria are satisfied. RSUs granted under the Restricted Share Unit Plan generally vest annually over a three year period. PSUs granted under the Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that the performance criteria have been satisfied, and that the holder remains actively employed, a director or a consultant with the Corporation on the vesting date.

	2015	2014
Outstanding, beginning of year	**2,745,439**	2,589,700
Granted	**1,996,841**	1,173,895
Vested and released	**(1,150,098)**	(927,351)
Forfeited	**(312,070)**	(90,805)
Outstanding, end of year	**3,280,112**	2,745,439

(e) Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of Deferred Share Units ("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 are vested when they are granted and are redeemed on the third business day following the date on which the holder ceases to be a director. At December 31, 2015, there were 47,696 DSUs outstanding (December 31, 2014 – 17,281).

(f) Contributed surplus:

	2015	2014
Balance, beginning of year	**$ 153,837**	$ 126,666
Stock-based compensation - expensed	**50,105**	48,310
Stock-based compensation - capitalized	**6,840**	14,174
RSUs vested and released	**(38,947)**	(31,814)
Stock options exercised	**–**	(3,499)
Balance, end of year	**$ 171,835**	$ 153,837

16. PETROLEUM REVENUE, NET OF ROYALTIES

For the years ended December 31	2015	2014
Petroleum revenue[(a)]:		
Proprietary	**$ 1,799,154**	$ 2,701,801
Third party[(b)]	**104,464**	149,260
	1,903,618	2,851,061
Royalties	**(20,765)**	(107,074)
Petroleum revenue, net of royalties	**$ 1,882,853**	$ 2,743,987

(a) The Corporation had three major customers each with revenue in excess of 10% of total petroleum revenue. Sales to major customers totaled $1.1 billion for the year ended December 31, 2015 (year ended December 31, 2014 - $1.4 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".

17. OTHER REVENUE

For the years ended December 31	2015	2014
Power revenue	**$ 29,239**	$ 55,352
Transportation revenue	**13,824**	30,625
Other revenue	**$ 43,063**	$ 85,977

18. DILUENT AND TRANSPORTATION

For the years ended December 31	2015	2014
Diluent	**$ 893,995**	$ 1,163,637
Transportation	**156,382**	64,442
Diluent and transportation	**$ 1,050,377**	$ 1,228,079

19. FOREIGN EXCHANGE LOSS, NET

For the years ended December 31	2015	2014
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ (852,422)**	$ (368,450)
US$ denominated cash, cash equivalents and other	**67,112**	35,301
Unrealized loss on foreign exchange	**(785,310)**	(333,149)
Realized loss on foreign exchange	**(16,429)**	(5,480)
Net foreign exchange loss	**$ (801,739)**	$ (338,629)

20. NET FINANCE EXPENSE

For the years ended December 31	2015	2014
Total interest expense	**$ 313,411**	$ 265,140
Less capitalized interest	**(56,449)**	(75,975)
Net interest expense	**256,962**	189,165
Accretion on decommissioning provision	**5,663**	4,535
Unrealized gain on derivative financial liabilities	**(13,289)**	(1,469)
Realized loss on interest rate swaps	**5,858**	5,056
Unrealized fair value gain on other assets	**–**	(429)
Net finance expense	**$ 255,194**	$ 196,858

21. OTHER EXPENSES

For the years ended December 31	2015	2014
Onerous contracts[(a)]	**$ 58,719**	$ –
Contract cancellation expense[(b)]	**12,879**	16,455
Inventory write-down[(c)]	**–**	19,668
Other expenses	**$ 71,598**	$ 36,123

(a) During the year ended December 31, 2015 the Corporation recognized an expense of $58.7 million related to certain onerous Calgary office lease contracts (note 13[(b)]) (December 31, 2014 - nil)

(b) The Corporation recognized a net contract cancellation expense of $12.9 million for the year ended December 31, 2015 comprised of an $18.3 million expense related to the termination of a marketing transportation contract and a $5.4 million recovery relating to the $16.5 million of project cancellation costs recorded in the fourth quarter of 2014.

(c) During the year ended December 31, 2014, the Corporation recognized a $19.7 million bitumen blend inventory write-down to net realizable value as a result of a decline in crude oil prices.

22. WAGES AND EMPLOYEE BENEFITS EXPENSE

For the years ended December 31	2015	2014
Operating expense:		
Salaries and wages	**$ 57,130**	$ 59,157
Short-term employee benefits	**6,101**	6,196
General and administrative expense:		
Salaries and wages	**78,394**	80,875
Short-term employee benefits	**12,153**	10,801
	$ 153,778	$ 157,029

23. TRANSACTIONS WITH RELATED PARTIES

During the year ended December 31, 2015, the Corporation paid $0.3 million in costs on behalf of WP Lexington Private Equity B.V. ("WP Lex"). WP Lex is considered to be a related party of the Corporation as two managing directors of WP Lex also hold positions as members of the Board of Directors of the Corporation.

The only other related party transactions during the years ended December 31, 2015 and December 31, 2014, was the compensation of key management personnel. The Corporation considers directors and officers of the Corporation as key management personnel.

For the years ended December 31	2015	2014
Salaries and short-term employee benefits	**$ 8,710**	$ 9,975
Share-based compensation expense	**13,323**	13,539
	$ 22,033	$ 23,514

24. SUPPLEMENTAL CASH FLOW DISCLOSURES

For the years ended December 31		2015		2014
Cash provided by (used in):[a]				
Trade receivables and other	**$**	**46,852**	$	9,941
Inventories		**47,492**		(30,519)
Accounts payable and accrued liabilities		**(228,808)**		11,622
	$	**(134,464)**	$	(8,956)
Changes in non-cash working capital relating to:				
Operating	**$**	**77,991**	$	(5,610)
Investing		**(212,455)**		(3,346)
	$	**(134,464)**	$	(8,956)
Cash and cash equivalents:[b]				
Cash	**$**	**222,341**	$	273,846
Cash equivalents		**185,872**		382,251
	$	**408,213**	$	656,097
Cash interest paid	**$**	**267,347**	$	236,410
Cash interest received	**$**	**2,860**	$	7,358

(a) The amounts for the year ended December 31, 2015, exclude non-cash working capital items primarily related to the $52.2 million transferred from inventory to other assets (Note 10).

(b) As at December 31, 2015, C$277.1 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars. (December 31, 2014 - C$404.9 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.3840 (December 31, 2014 - US$1 = C$1.1601).

25. NET LOSS PER COMMON SHARE

For the years ended December 31		2015		2014
Net loss	**$**	**(1,169,671)**	$	(105,538)
Weighted average common shares outstanding		**224,579,249**		223,314,791
Dilutive effect of stock options, RSUs and PSUs[a]		**–**		–
Weighted average common shares outstanding – diluted		**224,579,249**		223,314,791
Net loss per share, basic	**$**	**(5.21)**	$	(0.47)
Net loss per share, diluted	**$**	**(5.21)**	$	(0.47)

(a) For the years ended December 31, 2015 and December 31, 2014, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss during these periods. If the Corporation had recognized net earnings during the year ended December 31, 2015, the dilutive effect of stock options, RSUs and PSUs would have been 564,201 (year ended December 31, 2014 – 1,371,687) weighted average common shares.

26. 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, U.S. auction rate securities ("ARS") included within other assets, accounts payable and accrued liabilities, derivative financial liabilities and long-term debt. As at December 31, 2015, the ARS 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 ARS, long-term debt and derivative financial liabilities:

		Fair value measurements using		
As at December 31, 2015	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
ARS (note 10)	**$ 3,470**	**$ –**	**$ 3,470**	**$ –**
Financial liabilities				
Long-term debt[(1)] (note 12)	**5,257,124**	**–**	**3,999,317**	**–**
Derivative financial liabilities (note 13)	**16,223**	**–**	**16,223**	**–**

		Fair value measurements using		
As at December 31, 2014	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
ARS (note 10)	$ 2,908	$ –	$ 2,908	$ –
Financial liabilities				
Long-term debt[(1)] (note 12)	4,421,721	4,075,233	–	–
Derivative financial liabilities (note 13)	29,511	–	29,511	–

(1) *Long-term debt includes the current and long-term portions.*

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

As at December 31, 2015, 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 values of the ARS and long-term debt are derived using quoted prices in an inactive market from a third-party independent broker.

The fair value of derivative financial liabilities are derived using third-party valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates for the Corporation's interest rate swaps and floors. Management's assumptions rely on external observable market data including 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, 2015, 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. In 2015, the Corporation's long-term debt was transferred from Level 1 to Level 2 of the fair value hierarchy, as its fair value was derived from observable inputs from a third-party independent broker.

(b) 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. As noted below, in order to mitigate a portion of this risk, the Corporation has entered into interest rate swap contracts to effectively fix the interest rate on US$748.0 million of the US$1.249 billion senior secured term loan. Interest rate swaps are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

Amount	Effective date	Remaining term	Fixed rate	Floating rate
US$300 million	September 30, 2011	Jan 2016-Sept 2016	4.436%	3 month LIBOR(1)
US$150 million	December 31, 2011	Jan 2016-Sept 2016	4.376%	3 month LIBOR(1)
US$150 million	January 12, 2012	Jan 2016-Sept 2016	4.302%	3 month LIBOR(1)
US$148 million	January 27, 2012	Jan 2016-Sept 2016	4.218%	3 month LIBOR(1)

(1) London Interbank Offered Rate

As at December 31, 2015, a 100 basis points increase in LIBOR on floating rate debt, excluding the impact of interest capitalized, would have resulted in a $1.9 million decrease in net earnings before income taxes (December 31, 2014 - $1.4 million). As at December 31, 2015, a 100 basis points decrease in LIBOR, excluding the impact of interest capitalized, would have resulted in no impact on net earnings before income taxes (December 31, 2014 - $nil).

(c) 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, 2015, 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$38.0 million (December 31, 2014 - C$38.1 million).

(d) Commodity price risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. The Corporation's financial results may be significantly impacted by factors outside of the Corporation's control, including commodity prices and heavy oil differentials. Future fluctuations in commodity prices will affect the amount of revenue earned by the Corporation on the sale of its bitumen production and will impact the amount the Corporation pays for natural gas, electricity and diluent, which are all inputs into the steam-assisted gravity drainage production and transportation process. As at December 31, 2015, the Corporation did not have any derivative commodity contracts in place.

(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. At December 31, 2015, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $145.7 million. There were no significant trade receivables which were greater than 90 days as at December 31, 2015.

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 debt such as commercial, government and bank paper. The cash and cash equivalents balance at December 31, 2015 was $408.2 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 $408.2 million.

The Corporation's investments in ARS are subject to the credit risk associated with the counterparties to the investments. The Corporation's estimated maximum exposure to credit risk related to its investments in ARS is $3.5 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 earn enough income 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, 2015	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long-term debt	$ 5,257,124	$ 17,992	$ 35,984	$ 1,673,948	$ 3,529,200
Interest on long-term debt	1,919,974	299,394	596,764	547,850	475,966
Derivative financial liabilities	16,223	8,316	4,184	3,723	–
Accounts payable and accrued liabilities	143,907	143,907	–	–	–
	$ 7,337,228	**$ 469,609**	**$ 636,932**	**$ 2,225,521**	**$ 4,005,166**

As at December 31, 2014	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long-term debt	$ 4,421,721	$ 15,081	$ 30,162	$ 30,162	$ 4,346,316
Interest on long-term debt	1,862,853	251,735	501,922	499,511	609,685
Derivative financial liabilities	29,511	15,538	8,024	5,949	–
Accounts payable and accrued liabilities	366,374	366,374	–	–	–
	$ 6,680,459	**$ 648,728**	**$ 540,108**	**$ 535,622**	**$ 4,956,001**

27. GEOGRAPHICAL DISCLOSURE

As at December 31, 2015, the Corporation had non-current assets related to operations in the United States of $111.1 million (December 31, 2014 - $56.9 million). For the year ended December 31, 2015, petroleum revenue related to operations in the United States was $541.5 million (year ended December 31, 2014 - $131.4 million).

28. 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, 2015, the Corporation's proportionate interest in the joint operation's working capital balances was $5.0 million (December 31, 2014 - $24.6 million) and its interest in related pipeline assets, recorded in property, plant and equipment, was $1.1 billion (December 31, 2014 - $1.1 billion).

Operating commitments of $7.8 million and capital commitments of $1.4 million related to the joint operation are included within "Commitments" presented within Note 29[a].

29. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at December 31, 2015:

Operating

	2016	2017	2018	2019	2020	Thereafter
Transportation and storage	$ 177,466	$ 193,494	$ 207,276	$ 198,024	$ 239,117	$ 3,314,727
Office lease rentals	15,890	34,215	32,794	32,823	33,713	268,440
Diluent purchases	128,864	28,321	21,217	21,217	21,275	60,105
Other commitments	14,930	9,964	5,887	10,162	10,069	76,759
Commitments	**$ 337,150**	**$ 265,994**	**$ 267,174**	**$ 262,226**	**$ 304,174**	**$ 3,720,031**

Capital

As part of normal operations, the Corporation has entered into a total of $25.3 million in capital commitments to be made in periods through 2017.

(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.

30. CAPITAL DISCLOSURES

As at December 31, 2015, the Corporation's capital resources included $363.0 million of working capital, an additional undrawn US$2.5 billion syndicated revolving credit facility and a US$500.0 million guaranteed letter of credit facility under which US$179.2 million of letters of credit have been issued. Working capital is comprised of $408.2 million of cash and cash equivalents, offset by a non-cash working capital deficiency of $45.2 million.

The Corporation's cash is held in high interest savings accounts with a diversified group of highly-rated financial institutions. The Corporation has also invested in high grade, liquid, short-term instruments such as government, commercial and bank paper as well as term deposits. 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.

31. SUBSEQUENT EVENT

In the first quarter of 2016, the Corporation entered into derivative contracts to effectively fix the percentage differential between the price of West Texas Intermediate ("WTI") and the price of condensate for a portion of its condensate purchases. The use of derivative financial instruments is governed by a Risk Management Committee that follows guidelines and is subject to limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes.

Term	Contract	Volume (bbls/d)	Mont Belvieu/WTI %[a]
Apr. 1, 2016 – Dec. 31, 2016	Swap	6,000	82.8
Oct. 1, 2016 – Dec. 31, 2016	Swap	4,000	83.8
Jan. 1, 2017 – Dec. 31, 2017	Swap	10,000	81.3

(a) MEG has entered into swaps that effectively fix the average percentage differentials of condensate prices at Mont Belvieu, Texas to a percentage of WTI ($US/bbl).

BOARD OF DIRECTORS

Boyd Anderson [1, 3]
Lead Director, Independent

Harvey Doerr [1, 3]
Governance and Nominating Committee Chair,
Independent

Robert B. Hodgins [1, 2]
Audit Committee Chair,
Independent

Peter R. Kagan [3]
Independent

David B. Krieger [2]
Independent

William McCaffrey
Chairman,
President and Chief Executive Officer

Jeffrey J. McCaig [2, 3]
Independent

James D. McFarland [2, 3]
Compensation Committee Chair,
Independent

Diana McQueen
Independent

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1. *Audit Committee*
2. *Compensation Committee*
3. *Governance and Nominating Committee*

CORPORATE OFFICERS

William (Bill) McCaffrey
President and Chief Executive Officer

Eric Toews
Chief Financial Officer

Grant Boyd
Senior Vice President,
Resource Management –
Growth Properties

Jamey Fitzgibbon
Senior Vice President,
Resource Management –
Christina Lake and Special Projects

Don Moe
Senior Vice President,
Supply and Marketing

Richard Sendall
Senior Vice President,
Strategy and Government Relations

Chi-Tak Yee
Senior Vice President,
Reservoir and Geosciences

Grant Borbridge
Vice President, Legal,
General Counsel and Corporate Secretary

Stephen Diotte
Vice President, Human Resources,
Information Technology and Corporate Services

John McCoshen
Vice President, Finance and Treasurer

John Nearing
Vice President, Finance and Controller

John Rogers
Vice President, Investor Relations
and External Communications

Chris Sloof
Vice President, Projects

Don Sutherland
Vice President,
Regulatory and Community Relations

INFORMATION FOR SHAREHOLDERS

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

Transfer Agent

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Auditor

PricewaterhouseCoopers LLP

Independent Reserve Evaluator

GLJ Petroleum Consultants

Annual Meeting of Shareholders

June 28, 2016
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Further Information

MEG's financial reports, annual regulatory filings and news releases are available at www.sedar.com and on our website at www.megenergy.com.

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