FIRST QUARTER 2015

Report to Shareholders for the period ended March 31, 2015

MEG Energy Corp. reported first quarter 2015 operational and financial results on May 7, 2015. Highlights include:

- Record quarterly production of 82,398 barrels per day (bpd), an increase of 41% over first quarter 2014 production volumes, driven by the Christina Lake Phase 2B project and continuing implementation of MEG's RISER initiative;

- Net operating costs of $10.49 per barrel, 23% lower than first quarter 2014 costs and 13% below full-year 2014 costs of $12.06 per barrel;

- Cash flow used in operations of $0.13 per share, resulting from the low commodity price environment in the quarter, as well as higher diluent costs and wider light-heavy differentials in the month of January;

- Continuing strong financial liquidity, exiting the quarter with $471 million of cash and an undrawn US$2.5 billion credit facility.

"The quarter demonstrated continued strong operating results from our Christina Lake assets," said Bill McCaffrey, President and Chief Executive Officer. "It also emphasized the value of being a low-cost producer and the importance of maintaining that focus through the price cycles."

MEG reported cash flow used in operations of $29.5 million for the first quarter of 2015, compared to cash flow from operations of $157.0 million for the same period in 2014. Cash flow from operations decreased primarily due to a decline in benchmark WTI pricing in the quarter and, in January, both a widening of the light-heavy differential as well as increased cost of diluent, reflecting the drawdown of higher priced inventory. As a result, bitumen realizations decreased 59% from the first quarter of 2014.

"Our cash flow in the first quarter was impacted by certain transitional costs and pricing dynamics that we do not see continuing into the second quarter," says McCaffrey. "We are currently seeing positive signs as it relates to the realized price for our bitumen."

With the benefits from MEG's RISER initiative and strong and reliable production from Christina Lake Phase 2B, MEG reached a production record of 82,398 bpd in the first quarter of 2015, an increase of 41% over first quarter 2014 volumes of 58,643 bpd. MEG is targeting average production of 78,000 to 82,000 barrels per day in 2015 at an average non-energy operating cost of $8 to $10 per barrel, which includes the impact of two turnarounds planned in the second quarter of 2015.

"The ongoing application of the RISER initiative is showing strong results, with reservoir performance meeting or exceeding expectations," said McCaffrey. "To date we have tested the Phase 2B oil processing facility at 160% of its design capacity, and we are identifying low-cost options to significantly increase production beyond current levels. This will position us to grow in lower oil price environments in the future."

Net operating costs in the first quarter of 2015 averaged $10.49 per barrel compared to $13.63 per barrel in the first quarter of 2014. The decrease is primarily due to lower energy and non-energy operating costs per barrel, partially offset by a decrease in the average power sales price from MEG's cogeneration facilities.

MEG recognized an operating loss of $124.4 million in the first quarter of 2015, compared to operating earnings of $40.7 million for same period in 2014. Operating earnings decreased due to factors similar to those that affected bitumen price realizations, as well as higher transportation costs and an increase in depletion and depreciation expense, partially offset by higher sales volumes.

Forward-Looking Information and Non-GAAP Financial Measures

This quarterly report contains forward-looking information and financial measures that are not defined by International Financial Reporting Standards ("IFRS") and should be read in conjunction with the "Forward-Looking Information" and "Non-GAAP Financial Measures" sections of this quarter's Management's Discussion and Analysis.

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 period ended March 31, 2015 is dated May 6, 2015. 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, 2014 and the unaudited condensed consolidated interim financial statements and notes thereto for the period ended March 31, 2015. All tabular amounts are stated in thousands of Canadian dollars ($ or C$) unless indicated otherwise.

MD&A – Table of Contents

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. In a report dated effective December 31, 2014, with a preparation date of January 30, 2015, GLJ Petroleum Consultants Ltd. estimated that the oil sands leases it had evaluated contained 3.0 billion barrels of proved plus probable bitumen reserves and 3.8 billion barrels of contingent bitumen resources (best estimate).

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 of, the performance of, and the development schedule for, each expansion or phase in those projects. In addition, the Corporation holds other leases (the "Growth Properties") that are still in the resource definition stage and that are anticipated to provide significant additional development opportunities.

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. On July 16, 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 to Phases 1 and 2, the Corporation achieved average production in excess of 80,000 bbls/d from Christina Lake Phases 1, 2 and 2B in the fourth quarter of 2014.

The Corporation is currently focused on the expansion of the Christina Lake Project through the continuing application of RISER 2B. RISER 2B is an initiative that uses a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including a series of brownfield expansions of existing Phase 2B facilities. The Corporation anticipates this strategy will allow the Corporation to increase production more quickly and 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 strategic 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 the third quarter of 2014, MEG completed an expansion of the Access Pipeline, which included the construction of a 42-inch blend line from the Christina Lake Project to the Edmonton, Alberta area. The expansion of the Access Pipeline will accommodate anticipated increases in production from the Christina Lake Project as well as provide expansion capacity for future production volumes from the Surmont Project and from 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 owners of Access Pipeline may convert the system’s former 24-inch blend line to diluent service as diluent demand increases.

In addition to the Access Pipeline, MEG owns the Stonefell Terminal, located near Edmonton, Alberta. The Stonefell Terminal was commissioned in the fourth quarter of 2013 and has 900,000 barrels of strategic terminalling and storage capacity. The Stonefell Terminal is strategically located near the southern end of the Access Pipeline and 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 both the loading of bitumen blend for transport by rail and the receipt of railed diluent, giving direct access to multiple blend markets and diluent sources throughout North America.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The first quarter of 2015 experienced a significant decline in crude oil prices from the fourth quarter of 2014, coupled with a substantial decline in the value of the Canadian dollar relative to the U.S. dollar. These factors significantly impacted the Corporation's financial results.

The Corporation's blend sales are determined by reference to U.S. benchmark crude oil prices. Benchmark Brent and West Texas Intermediate ("WTI") declined 28% and 34%, respectively, from the fourth quarter of 2014, averaging US$55.16 and US$48.63 per barrel in the first quarter of 2015. In addition, the WTI:WCS ("Western Canadian Select") differential widened from an average of 19.7% in the fourth quarter of 2014 to 30.2% in the first quarter of 2015.

The crude oil price differential MEG receives for its blend throughout each calendar month, consistent with industry practice, is established prior to the determination of the monthly U.S. benchmark crude oil price, which can result in a temporary widening of differentials on a percentage basis in times of significant and unexpected reductions in benchmark crude oil prices as was experienced in the first quarter of 2015. In contrast, in periods of significant increases in benchmark crude oil prices, these differentials can narrow.

Diluent costs represent MEG's largest input cost to production. The Corporation's cost of diluent in the first quarter of 2015 was impacted by the transitional impact of diluent inventory that had been purchased at a higher weighted-average cost during the fourth quarter of 2014.

As a result of the factors outlined above, average bitumen realizations declined 49% in the first quarter of 2015, compared to the fourth quarter of 2014.

Changes in the value of the Canadian dollar relative to the U.S. dollar also have an impact on revenues and earnings, as a decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on blend sales revenues, but has a negative impact on principal and interest payments. Translation of the net amount of the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents can lead to significant net unrealized losses during periods of rapid deterioration of the Canadian dollar compared to the U.S. dollar. The Corporation recognizes unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt at the end of each reporting period. As at March 31, 2015, the Canadian dollar had decreased in value by approximately 9% against the U.S. dollar compared to its value as at December 31, 2014. The impact of this change during the quarter largely contributed to the net loss during the quarter, which includes a net unrealized foreign exchange loss related to the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.

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

	2015	2014				2013		
($ millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Bitumen production - bbls/d	**82,398**	80,349	76,471	68,984	58,643	42,251	34,246	32,144
Bitumen sales - bbls/d	**85,519**	70,116	69,757	70,849	58,089	35,990	32,175	32,175
Bitumen realization - $/bbl	**25.82**	50.48	65.12	72.75	62.28	38.22	74.33	53.98
Net operating costs - $/bbl(1)	**10.49**	10.13	10.31	14.49	13.63	11.22	9.40	8.85
Non-energy operating costs - $/bbl	**7.57**	6.42	7.16	9.64	9.05	8.09	9.20	10.00
Cash operating netback(2) - $/bbl	**9.83**	35.56	48.70	51.45	43.51	23.78	59.59	41.93
Cash flow from (used in) operations(3)	**(30)**	134	238	262	157	23	144	79
Per share, diluted(3)	**(0.13)**	0.60	1.06	1.16	0.70	0.10	0.64	0.35
Operating earnings (loss)(3)	**(124)**	8	87	111	41	(33)	56	14
Per share, diluted(3)	**(0.56)**	0.04	0.39	0.49	0.18	(0.15)	0.25	0.25
Revenue (4)	**467**	615	706	829	680	350	402	324
Net earnings (loss)(5)	**(508)**	(150)	(101)	249	(103)	(148)	115	(62)
Per share, basic	**(2.27)**	(0.67)	(0.45)	1.12	(0.46)	(0.67)	0.52	(0.28)
Per share, diluted	**(2.27)**	(0.67)	(0.45)	1.11	(0.46)	(0.67)	0.51	(0.28)
Total cash capital investment(6)	**80**	324	291	299	324	366	455	636
Cash, cash equivalents and short-term investments	**471**	656	777	840	890	1,179	647	1,204
Long-term debt(7)	**4,776**	4,366	4,218	4,016	4,162	4,005	2,858	2,923

(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 basis.*

(3) *Cash flow from (used in) operations, Operating earnings (loss), 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. These non-GAAP measures are reconciled to net loss and net cash provided by (used in) 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 Interim Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss).*

(5) *Includes a net unrealized foreign exchange loss of $371 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents for the three months ended March 31, 2015. The net loss for the three months ended March 31, 2014 included a net unrealized foreign exchange loss of $141 million.*

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

(7) *Includes current and long-term portions, as presented on the Consolidated Balance Sheet.*

Bitumen Production

Bitumen production for the three months ended March 31, 2015 averaged 82,398 bbls/d compared to 58,643 bbls/d for the three months ended March 31, 2014. The increase in production volumes is primarily due to the successful ramp-up of Phase 2B and the implementation of 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.

Bitumen Sales

Bitumen sales for the three months ended March 31, 2015 were 85,519 bbls/d compared to production of 82,398 bbls/d for the same period. The difference between bitumen sales and production was primarily due to a decrease in the inventory volumes in-transit by rail and on the Flanagan-Seaway Pipeline.

Bitumen Realization

Bitumen realization, as discussed in this MD&A, represents the Corporation's realized proprietary blend sales revenues, net of the cost of diluent. Proprietary petroleum sales represents MEG's revenue from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). AWB is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. The cost of blending is impacted by the amount of diluent required and the Corporation's cost of purchasing diluent. A portion of the cost of diluent is effectively recovered in the sales price of the blended product. The cost of diluent is impacted by U.S. benchmark pricing and the timing of diluent inventory purchases.

For the three months ended March 31, 2015, average bitumen realizations decreased to $25.82 per barrel compared to $62.28 per barrel for the three months ended March 31, 2014. The decrease in bitumen realization is a result of the significant decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue. In addition, the decrease in diluent costs in the first quarter of 2015 was proportionately less than the decrease in blend sales revenues, compared to the first quarter of 2014. The lower than expected decrease in diluent costs was primarily related to the transitional impact of diluent inventory that had been purchased at a higher weighted-average cost during the fourth quarter of 2014.

The C$/bbl WTI price averaged $60.35 per barrel during the three months ended March 31, 2015 compared to $108.89 per barrel during the three months ended March 31, 2014. The WTI:WCS differential increased to an average of 30.2% for the three months ended March 31, 2015 compared to 23.4% for the three months ended March 31, 2014. The benchmark crude oil price differential MEG receives for its blend throughout each calendar month, consistent with industry practice, is established prior to the determination of the monthly U.S. benchmark crude oil price, which can result in temporary widening of differentials on a percentage basis in times of significant and unexpected reductions in benchmark crude oil prices as was experienced in the first quarter of 2015. In contrast, in periods of significant increases in benchmark crude oil prices, these differentials can narrow.

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 three months ended March 31, 2015 averaged $10.49 per barrel compared to $13.63 per barrel for the three months ended March 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 the average power sales price.

- Energy operating costs decreased to $4.07 per barrel for the three months ended March 31, 2015 compared to $8.43 per barrel for the same period in 2014. Energy costs decreased as a result of the decline in natural gas prices, which decreased to an average of $3.19 per mcf for the three months ended March 31, 2015 compared to $6.09 per mcf for the same period in 2014.

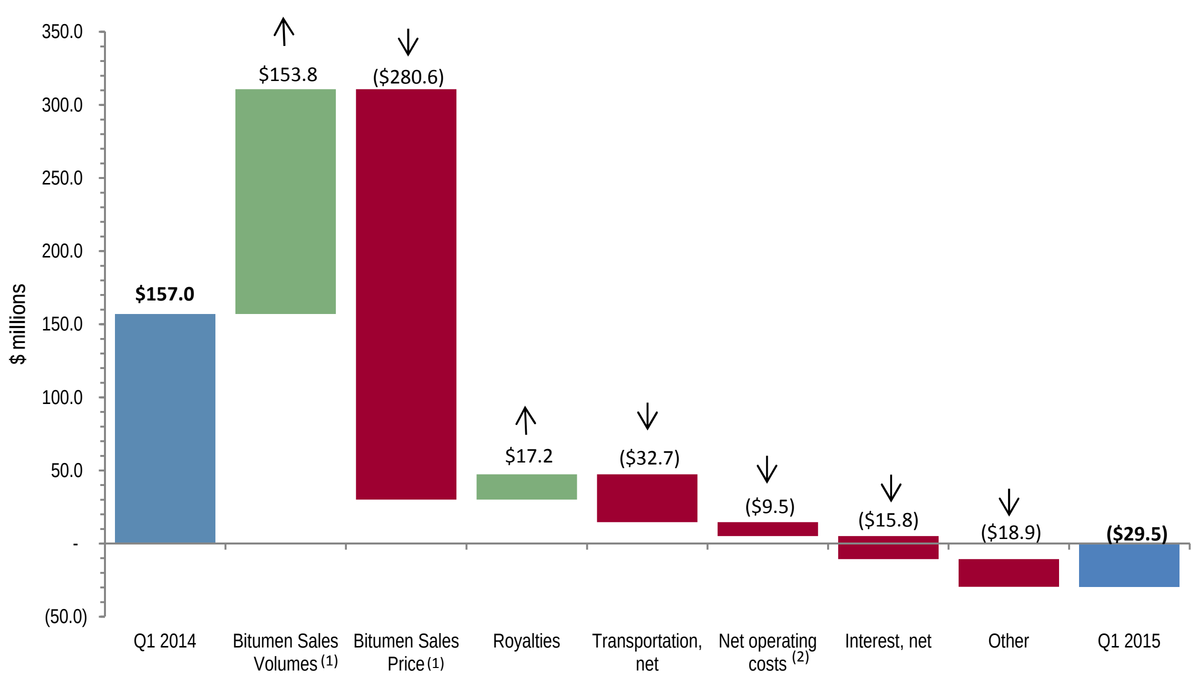
- Non-energy operating costs decreased to $7.57 per barrel for the three months ended March 31, 2015 compared to $9.05 per barrel for the same period in 2014. On a per barrel basis, non-energy operating costs decreased primarily as a result of the increase in production and sales volumes, as relatively fixed components of operating costs are spread over a greater number of barrels.

- Power revenue decreased to $1.15 per barrel for the three months ended March 31, 2015 compared to $3.85 per barrel for the same period in 2014. The Corporation's realized power price during the three months ended March 31, 2015 decreased to $28.21 per megawatt hour compared to $62.26 per megawatt hour for the same period in 2014. The decrease in the power price is mainly a result of increased power generation capacity in the province of Alberta. Power revenue had the effect of offsetting 28% of energy operating costs during the three months ended March 31, 2015 compared to offsetting 46% of energy operating costs during the same period in 2014.

Cash Operating Netback

Cash operating netback for the three months ended March 31, 2015 was $9.83 per barrel compared to $43.51 per barrel for the three months ended March 31, 2014. The decrease in the cash operating netback is primarily due to a decrease in bitumen realizations. The decrease in bitumen realizations is directly correlated to the significant decline of U.S. crude oil benchmark pricing. In addition, the WTI:WCS differential widened and the decrease in the cost of diluent in the first quarter of 2015 was proportionately less than the decrease in blend sales revenues, compared to the first quarter of 2014. This was partially offset by a per barrel decrease in royalties and net operating costs.

Cash Flow from (Used In) Operations



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

Cash flow from operations was a use of funds of $29.5 million for the three months ended March 31, 2015 compared to cash flow from operations of $157.0 million for the three months ended March 31, 2014. Cash flow from operations decreased primarily due to lower bitumen realizations and higher transportation costs, partially offset by higher sales volumes. The decrease in bitumen realizations is directly correlated to the significant decline of U.S. crude oil benchmark pricing. In addition, the WTI:WCS differential widened and the decrease in the cost of diluent was proportionately less than the decrease in blend sales revenues, compared to the first quarter of 2014. Transportation expense increased by $32.7 million 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 increased transportation costs associated with rail and also due to lower transportation revenues from third parties.

Operating Earnings (Loss)

The Corporation recognized an operating loss of $124.4 million for the three months ended March 31, 2015 compared to operating earnings of $40.7 million for the three months ended March 31, 2014. Operating earnings have decreased in the first quarter of 2015 due to lower bitumen realizations, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, higher transportation costs and an increase in depletion and depreciation expense, partially offset by higher sales volumes.

Revenue

Revenue for the three months ended March 31, 2015 totalled $467.0 million compared to $679.6 million for the three months ended March 31, 2014. Revenue represents the total of Petroleum revenue, net of royalties and Other revenue.

Net Earnings (Loss)

The Corporation recognized a net loss of $508.3 million for the three months ended March 31, 2015 compared to a net loss of $103.4 million for the three months ended March 31, 2014. The net loss for the three months ended March 31, 2015 included a net unrealized foreign exchange loss of $370.8 million on the Corporation’s U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents. The net loss for the three months ended March 31, 2014 included a net unrealized foreign exchange loss of $140.6 million on U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents.

Total Cash Capital Investment

Total cash capital investment during the three months ended March 31, 2015 totalled $80.1 million compared to a total of $323.5 million for the three months ended March 31, 2014. Capital investment in 2015 has been 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 $470.8 million as at March 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 due to lower cash flow from operations in the three months ended March 31, 2015 as a result of the decline in bitumen realizations, an increase in non-cash working capital and, to a lesser extent, capital investment activity during the quarter.

All of the Corporation's long-term debt is denominated in U.S. dollars. Long-term debt increased to C$4.8 billion as at March 31, 2015 from C$4.4 billion as at December 31, 2014 due to the decrease in the value of the Canadian dollar relative to the U.S. dollar. 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 March 31, 2015, the Corporation's capital resources included $470.8 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. 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.

3. OUTLOOK

Annual non-energy operating costs for 2015 are targeted to be in the range of $8 to $10 per barrel and annual bitumen production volumes are targeted to be in the 78,000 to 82,000 bbls/d range, while providing for two scheduled plant turnarounds. The Corporation's 2015 planned capital program totals $305 million.

4. BUSINESS ENVIRONMENT

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

	2015	2014				2013		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Average Commodity Prices								
Crude oil prices								
Brent (US$/bbl)	**55.16**	76.98	103.39	109.77	107.90	109.35	109.71	103.35
WTI (US$/bbl)	**48.63**	73.15	97.16	102.99	98.68	97.43	105.83	94.22
WTI (C$/bbl)	**60.35**	83.08	105.84	112.31	108.89	102.08	109.90	96.42
Differential – Brent:WTI (US$/bbl)	**6.53**	3.83	6.23	6.78	9.22	11.92	3.88	9.13
Differential – Brent:WTI (%)	**11.8%**	5.0%	6.0%	6.2%	8.5%	10.9%	3.5%	8.8%
WCS (C$/bbl)	**42.13**	66.74	83.82	90.44	83.41	68.31	91.75	76.82
Differential – WTI:WCS (C$/bbl)	**18.22**	16.34	22.02	21.87	25.48	33.77	18.15	19.60
Differential – WTI:WCS (%)	**30.2%**	19.7%	20.8%	19.5%	23.4%	33.1%	16.5%	20.3%
Condensate prices								
C5+ at Edmonton (C$/bbl)	**56.59**	81.98	101.72	114.72	113.26	99.19	107.81	103.68
Natural gas prices								
AECO (C$/mcf)	**2.74**	3.58	4.00	4.70	5.69	3.52	2.42	3.51
Electric power prices								
Alberta power pool (C$/MWh)	**29.14**	30.55	63.91	42.43	60.58	48.60	83.61	123.41
Foreign exchange rates								
C$ equivalent of 1 US$ - average	**1.2411**	1.1357	1.0893	1.0905	1.1035	1.0477	1.0385	1.0233
C$ equivalent of 1 US$ - period end	**1.2683**	1.1601	1.1208	1.0676	1.1053	1.0636	1.0285	1.0512

Crude Oil Pricing

Brent crude is a major representative of global light sweet crude oil prices and serves as a benchmark price. The Brent benchmark price averaged US$55.16 per barrel in the first quarter of 2015 compared to US$76.98 per barrel for the fourth quarter of 2014 and US$107.90 per barrel for the first quarter of 2014. The decrease is primarily due to a global imbalance between supply and demand for crude oil.

The price of WTI is the current benchmark for mid-continent North American crude oil prices, at Cushing Oklahoma, and its Canadian dollar equivalent is the basis for determining royalties on the Corporation's bitumen sales. The WTI price averaged US$48.63 per barrel in the first quarter of 2015 compared to US$73.15 per barrel for the fourth quarter of 2014 and US$98.68 per barrel for the first quarter of 2014. The decrease is primarily due to a global imbalance between supply and demand for crude oil.

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 $18.22 per barrel or 30.2% for the first quarter of 2015, compared to $25.48 per barrel or 23.4% for the first quarter of 2014.

Pipeline congestion and consequent apportionment of capacity between western Canada and the U.S. coastal markets can negatively impact the price MEG receives for its blend sales. Recent additions of crude-by-rail, new pipeline connections from the U.S. mid-continent to the U.S. Gulf Coast, and refinery modifications in the U.S. Midwest, are collectively working towards relieving some of this price pressure.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, as it is used to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facilities. The AECO natural gas price averaged $2.74 per mcf for the three months ended March 31, 2015 compared to $5.69 per mcf for the three months ended March 31, 2014. Natural gas prices have weakened due to record production levels in the U.S., strong production in Alberta, an increase of gas in storage and reduced demand as a result of mild winter conditions across North America.

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 $29.14 per megawatt hour for the three months ended March 31, 2015 compared to $60.58 per megawatt hour for the three months ended March 31, 2014. The decrease in the Alberta power pool price is mainly a result of increased year-over-year power generation capacity in the province. This increased power generation in the province is anticipated to continue to moderate power prices.

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, as blend sales prices 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 revenues and a negative impact on principal and interest payments, while an increase in the value of the Canadian dollar has a negative impact on blend sales revenues and a positive impact on principal and interest payments. The Corporation recognizes net unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents at each reporting date. As at March 31, 2015, the Canadian dollar, at a rate of 1.2683, had decreased in value by approximately 9% against the U.S. dollar compared to its value as at December 31, 2014, when the rate was 1.1601. During the three months ended March 31, 2014, the Canadian dollar weakened in value by approximately 4%.

5. RESULTS OF OPERATIONS

	Three months ended March 31	
	2015	**2014**
Bitumen production – bbls/d	**82,398**	58,643
Bitumen sales – bbls/d	**85,519**	58,089
Steam to oil ratio (SOR)	**2.6**	2.5

Bitumen Production

Production for the three months ended March 31, 2015 averaged 82,398 bbls/d compared to 58,643 bbls/d for the three months ended March 31, 2014. The increase in production volumes for the three months ended March 31, 2015 compared to the three months ended March 31, 2014 is due to the successful ramp-up of Phase 2B and the implementation of 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 on production.

Bitumen Sales

Bitumen sales for the three months ended March 31, 2015 were 85,519 bbls/d compared to production of 82,398 bbls/d for the same period. The difference between bitumen sales and production was primarily due to a decrease in the inventory volumes in-transit by rail and on the Flanagan-Seaway Pipeline.

Steam to Oil Ratio

The Corporation continues to focus on increasing production and improving efficiency of current production through a lower steam to oil ratio (“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 2.6 during the three months ended March 31, 2015 and 2.5 for the three months ended March 31, 2014. The increase in the SOR in the first quarter of 2015 is due to additional steam being directed to wells that are not yet in production mode.

Operating Cash Flow

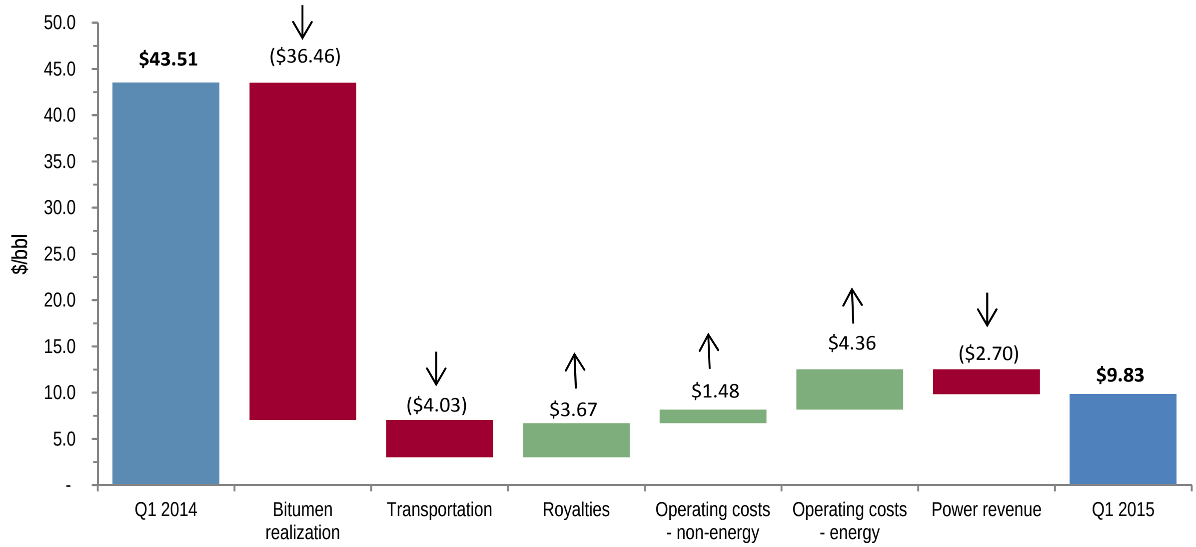
		Three months ended March 31
($000)	**2015**	**2014**
Petroleum sales – proprietary[1]	**$ 455,753**	$ 601,828
Diluent	**(257,048)**	(276,208)
	198,705	325,620
Royalties	**(6,150)**	(23,383)
Transportation expense	**(38,662)**	(12,890)
Operating expenses	**(89,598)**	(91,390)
Power revenue	**8,819**	20,131
Transportation revenue	**2,494**	9,379
Operating cash flow[2]	**$ 75,608**	$ 227,467

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

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

Operating cash flow decreased primarily due to lower bitumen realizations as a result of the significant decline of U.S. crude oil benchmark pricing, widening of the WTI:WCS differential and higher transportation costs, partially offset by higher sales volumes. Blend sales for the three months ended March 31, 2015 were $455.8 million compared to $601.8 million for the three months ended March 31, 2014. The decrease in blend sales in the first quarter of 2015 compared to the first quarter of 2014 is due to a 48% decrease in the average realized blend price partially offset by a 46% increase in sales volumes. The cost of diluent for the three months ended March 31, 2015 was $257.0 million compared to $276.2 million for the three months ended March 31, 2014. The total 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. The cost of diluent decreased 7% in the first quarter in 2015 from the first quarter of 2014 compared to a 24% decrease in blend sales revenues for the same period. The decrease in the cost of diluent in the first quarter of 2015 was proportionately less than the decrease in blend sales revenue, primarily due to the transitional impact of diluent inventory that had been purchased at a higher weighted-average cost during the fourth quarter of 2014.

Cash Operating Netback



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

	Three months ended March 31	
($/bbl)	**2015**	**2014**
Bitumen realization[1]	**$ 25.82**	$ 62.28
Transportation[2]	**(4.70)**	(0.67)
Royalties	**(0.80)**	(4.47)
	20.32	57.14
Operating costs – non-energy	**(7.57)**	(9.05)
Operating costs – energy	**(4.07)**	(8.43)
Power revenue	**1.15**	3.85
Net operating costs	**(10.49)**	(13.63)
Cash operating netback	**$ 9.83**	$ 43.51

(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 represents the Corporation's realized proprietary blend sales revenues, net of the cost of diluent. Bitumen realization averaged $25.82 per barrel for the three months ended March 31, 2015 compared to $62.28 per barrel for the three months ended March 31, 2014. The decrease in bitumen realization is primarily as a result of the significant decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue. In addition, the decrease in the cost of diluent in the first quarter of 2015 was proportionately less than the decrease in blend sales revenues, compared to the first quarter of 2014.

For the three months ended March 31, 2015, the Corporation's cost of diluent was $69.20 per barrel compared to $106.57 per barrel for the three months ended March 31, 2014. The cost of diluent, on a per barrel basis, decreased 35% in the first quarter in 2015 from the first quarter of 2014 compared to a 48% decrease in blend sales for the same period. The decrease in the cost of diluent in the first quarter of 2015 was proportionately less than the decrease in blend sales revenues, primarily due to the transitional impact of diluent inventory that had been purchased at a higher weighted-average cost during the fourth quarter of 2014.

Transportation

Transportation costs include rail, Stonefell Terminal costs and third-party pipelines as well as MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries on diluent transportation arrangements. Transportation costs averaged $4.70 per barrel for the three months ended March 31, 2015 compared to $0.67 per barrel for the three months ended March 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, in addition to increased transportation costs associated with rail and also due to 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 depending on whether a project is pre-payout or post-payout, with payout being defined as the point in time when a project has generated enough 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 $0.80 per barrel during the three months ended March 31, 2015 compared to $4.47 per barrel for the three months ended March 31, 2014. The decrease in royalties for the three months ended March 31, 2015 compared to the same period in 2014 is 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 averaged $7.57 per barrel for the three months ended March 31, 2015 compared to $9.05 per barrel for the three months ended March 31, 2014. Non-energy operating costs increased in aggregate primarily due to the increase in sales volumes. On a per barrel basis, non-energy costs decreased in the first quarter of 2015 due to the Phase 2B ramp-up costs incurred in the first quarter of 2014 and due to higher sales volumes, as relatively fixed components of operating costs are spread over a greater number of barrels.

Energy related operating costs

Energy related operating costs averaged $4.07 per barrel for the three months ended March 31, 2015 compared to $8.43 per barrel for the three months ended March 31, 2014. The decrease in energy operating costs on a per barrel basis is attributable to the decrease in natural gas prices. The

Corporation's natural gas purchase price averaged $3.19 per mcf during the first quarter of 2015 compared to $6.09 per mcf for the first quarter of 2014.

Power revenue

Power revenue averaged $1.15 per barrel for the three months ended March 31, 2015 compared to $3.85 per barrel for the three months ended March 31, 2014. The Corporation's average realized power sales price during the three months ended March 31, 2015 was $28.21 per megawatt hour compared to $62.26 per megawatt hour for the same period in 2014. The decrease in the power sales price is mainly a result of increased power generation capacity in the province of Alberta.

6. OTHER OPERATING RESULTS

Net Marketing Activity

	Three months ended March 31	
($000)	**2015**	**2014**
Petroleum sales – third party	**$ 6,079**	$ 71,607
Purchased product and storage:		
Purchased product	**(6,042)**	(68,240)
Marketing and storage arrangements	**(6,065)**	(3,422)
	(12,107)	(71,662)
Net marketing activity[1]	**$ (6,028)**	$ (55)

(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 in the United States. Accordingly, the Corporation has entered into product storage arrangements and marketing arrangements for rail, barge and U.S.-based pipelines. These arrangements are kept in place 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

	Three months ended March 31	
($000)	**2015**	**2014**
Depletion and depreciation	**$ 115,571**	$ 81,244
Depletion and depreciation per barrel	**$ 15.02**	$ 15.54

Depletion and depreciation expense for the three months ended March 31, 2015 totalled $115.6 million compared to $81.2 million for the three months ended March 31, 2014. The increase is primarily due to a 47% increase in bitumen sales volumes for the three months ended March 31, 2015, compared to the three months ended March 31, 2014. Depletion and depreciation expense was $15.02 per barrel for the three months ended March 31, 2015 compared to $15.54 per barrel for the three months ended March 31, 2014.

The Corporation's producing oil sands properties are depleted on a unit-of-production basis based on estimated proved reserves. Major facilities and equipment are depreciated on a unit-of-production basis over the estimated total productive capacity of the facilities and equipment. Pipeline and storage assets are depreciated on a straight-line basis over their estimated useful lives.

General and Administrative

	Three months ended March 31	
($000)	**2015**	**2014**
General and administrative costs	**$ 39,634**	$ 35,189
Capitalized general and administrative costs	**(6,328)**	(8,814)
General and administrative expense	**$ 33,306**	$ 26,375
General and administrative expense per barrel of production	**$ 4.49**	$ 5.00

General and administrative expense for the three months ended March 31, 2015 was $33.3 million compared to $26.4 million for the three months ended March 31, 2014. The increase in general and administrative expense, after capitalization, is primarily due to a decrease in the capitalization rate in the first quarter of 2015 compared to the first quarter of 2014 as a result of a reduction of capital investing activity.

The increase in general and administrative expense was offset on a per barrel basis by higher production volumes, as expenses are spread over a greater number of barrels, which more than offset an increase in costs.

Stock-based Compensation

	Three months ended March 31	
($000)	**2015**	**2014**
Stock-based compensation costs	**$ 14,107**	$ 15,638
Capitalized stock-based compensation costs	**(1,577)**	(3,016)
Stock-based compensation expense	**$ 12,530**	$ 12,622

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, before capitalization, for the three months ended March 31, 2015 was $14.1 million compared to $15.6 million for three months ended March 31, 2014.

The Corporation capitalizes a portion of stock-based compensation associated with capitalized salaries and benefits. The Corporation capitalized $1.6 million of stock-based compensation for the three months ended March 31, 2015 compared to $3.0 million for three months ended March 31, 2014. The decrease in capitalized stock-based compensation is primarily due to a decrease in the capitalization rate as a result of a reduction of capital investing activity.

Research and Development

	Three months ended March 31	
($000)	**2015**	**2014**
Research and development	**$ 1,172**	$ 991

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 $1.2 million for the three months ended March 31, 2015 compared to $1.0 million for the three months ended March 31, 2014.

Net Foreign Exchange Gain (Loss)

	Three months ended March 31	
($000)	**2015**	**2014**
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ (412,406)**	$ (159,485)
US$ denominated cash and cash equivalents	**41,557**	18,884
Unrealized net loss on foreign exchange	**(370,849)**	(140,601)
Realized loss on foreign exchange	**(7,230)**	(2,643)
Foreign exchange loss, net	**$ (378,079)**	$ (143,244)

US$/C$ exchange rates:		
Beginning of period	**1.1601**	1.0636
End of period	**1.2683**	1.1053

The Corporation recognized a net foreign exchange loss of $378.1 million for the three months ended March 31, 2015 compared to a net foreign exchange loss of $143.2 million for the three months ended March 31, 2014. The increase in the net foreign exchange loss is primarily due to an unrealized foreign exchange loss on the translation of 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 three months ended March 31, 2015. During the three months ended March 31, 2014, the Canadian dollar weakened in value by approximately 4%.

Net Finance Expense

	Three months ended March 31	
($000)	**2015**	**2014**
Total interest expense	**$ 75,726**	$ 65,700
Less capitalized interest	**(16,003)**	(19,470)
Net interest expense	**59,723**	46,230
Accretion on decommissioning provision	**1,312**	1,037
Unrealized fair value loss (gain) on embedded derivative financial liabilities	**5,087**	(1,110)
Unrealized fair value gain on interest rate swaps	**(1,556)**	(517)
Realized loss on interest rate swaps	**1,401**	1,121
Net finance expense	**$ 65,967**	$ 46,761

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 three months ended March 31, 2015 was $75.7 million compared to $65.7 million for the three months ended March 31, 2014. Total interest expense for the three months ended March 31, 2015 increased primarily due to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense.

The Corporation recognized an unrealized loss on embedded derivative financial liabilities of $5.1 million for the three months ended March 31, 2015 compared to an unrealized gain of $1.1 million for the three months ended March 31, 2014. These gains and losses relate to the change in fair value of the interest rate floor associated with the Corporation's senior secured credit facilities. The interest rate floor is considered an embedded derivative as the floor rate was higher than the London Interbank Offered Rate ("LIBOR") at the time that the debt agreements were entered into. Accordingly, the fair value of the embedded derivatives at the time the debt agreements were entered into was netted against the carrying value of the long-term debt and is amortized over the life of the debt agreements. The fair value of the embedded derivative is included in derivative financial liabilities on the balance sheet, with gains and losses associated with changes in the fair value of the embedded derivative included in net finance expense.

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$1.3 billion senior secured term loan until September 30, 2016. The Corporation recognized an unrealized gain of $1.6 million on the interest rate swap contracts for the three months ended March 31, 2015, compared to an unrealized gain of $0.5 million for three months ended March 31, 2014. In addition, the Corporation recognized a realized loss of $1.4 million for the three months ended March 31, 2015 compared to a realized loss of $1.1 million for the three months ended March 31, 2014.

Income Taxes

	Three months ended March 31	
($000)	2015	2014
Deferred income tax expense (recovery)	**$ (27,774)**	$ 22,876

The Corporation recognized a deferred income tax recovery of $27.8 million for the three months ended March 31, 2015 compared to a deferred income tax expense of $22.9 million for the three months ended March 31, 2014.

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 three months ended March 31, 2015, the non-taxable loss was $206.2 million compared to a non-taxable loss of $79.7 million for the three months ended March 31, 2014.

- Stock-based compensation expense for the three months ended March 31, 2015 of $12.5 million compared to $12.6 million for the three months ended March 31, 2014.

The Corporation is not currently taxable. As of March 31, 2015, the Corporation had approximately $7.0 billion of available tax pools and had recognized a deferred income tax liability of $150.4 million. In addition, at March 31, 2015, the Corporation had $924.0 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects. As at March 31, 2015, the Corporation had not recognized the tax benefit related to $479.5 million of unrealized taxable capital foreign exchange losses.

7. TOTAL CASH AND NON-CASH CAPITAL INVESTING

	Three months ended March 31	
($000)	2015	2014
Total cash capital investment	**$ 80,101**	$ 323,533
Capitalized interest	**16,003**	19,470
	96,104	343,003
Non-cash capital investment	**18,827**	10,562
Total cash and non-cash capital investment	**$ 114,931**	$ 353,565

MEG’s total cash and non-cash capital investment for the three months ended March 31, 2015 was $114.9 million (including capitalized interest of $16.0 million and non-cash capital investment of $18.8 million) in comparison to $353.6 million (including capitalized interest of $19.5 million and non-cash capital investment of $10.6 million) for the three months ended March 31, 2014.

Total cash capital investment for the three months ended March 31, 2015 was $80.1 million in comparison to $323.5 million for the three months ended March 31, 2014. Total cash capital investing for the first quarter of 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.

The Corporation capitalizes interest associated with qualifying assets. A total of $16.0 million of interest was capitalized during the three months ended March 31, 2015.

Non-cash capital investment for the three months ended March 31, 2015 included a $17.0 million provision for future reclamation and decommissioning and $1.6 million in capitalized stock-based compensation.

8. LIQUIDITY AND CAPITAL RESOURCES

($000)	March 31, 2015	December 31, 2014
Cash and cash equivalents	**$ 470,778**	$ 656,097
Senior secured term loan (March 31, 2015 – US$1.258 billion; December 31, 2014 – US$1.262 billion; due 2020)	**1,595,838**	1,463,466
US$2.5 billion revolver (due 2019)	**-**	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	**951,225**	870,075
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,014,640**	928,080
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,268,300**	1,160,100
Total debt(1)	**$4,830,003**	$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 interim consolidated financial statements as at March 31, 2015 and the Corporation's consolidated financial statements as at December 31, 2014.*

Capital Resources

As at March 31, 2015, the Corporation's available capital resources included $470.8 million of cash and cash equivalents and an additional undrawn US$2.5 billion syndicated revolving credit facility and a US$500 million guaranteed letter of credit facility, under which US$157.5 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 March 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. 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 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$1.3 billion senior secured term loan until September 30, 2016.

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.

Cash Flow Summary

	Three months ended March 31	
($000)	**2015**	**2014**
Net cash provided by (used in):		
Operating activities	**$ (16,942)**	$ 39,049
Investing activities	**(205,810)**	(344,711)
Financing activities	**(4,124)**	(1,959)
Foreign exchange gains on cash and cash equivalents held in foreign currency	**41,557**	18,884
Change in cash and cash equivalents	**$ (185,319)**	$ (288,737)

Cash Flow – Operating Activities

Net cash used in operating activities totalled $16.9 million for the three months ended March 31, 2015 compared to net cash provided by operating activities of $39.0 million for the three months ended March 31, 2014. The decrease in cash flow from operating activities is primarily due to lower bitumen realizations and higher transportation costs, partially offset by higher sales volumes. The lower bitumen realizations is directly correlated to the significant decline of U.S. crude oil benchmark pricing. In addition, the WTI:WCS differential widened and the cost of diluent was proportionately less than the decrease in blend sales revenues, compared to the first quarter of 2014. The lower than expected decrease in diluent costs was primarily related to the transitional impact of diluent inventory that had been purchased at a higher weighted-average cost during the fourth quarter of 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, in addition to increased transportation costs associated with rail and also due to lower transportation revenues from third parties.

Net cash used in operating activities for the first quarter of 2015 included an increase in the net change in non-cash working capital of $13.5 million, primarily as a result of the first quarter sales of blend and bitumen inventory on hand at December 31, 2014.

Cash Flow – Investing Activities

Net cash used in investing activities for the three months ended March 31, 2015 primarily consisted of $96.1 million in capital investment, including $16.0 million of capitalized interest, (refer to the "CAPITAL INVESTING" section of this MD&A for further details) and a $111.6 million decrease in the net change in non-cash investing working capital.

Net cash used in investing activities for the three months ended March 31, 2014 primarily consisted of $343.0 in capital investment, including $19.5 million of capitalized interest.

Cash Flow – Financing Activities

Net cash used in financing activities for the three months ended March 31, 2015 consisted of $4.1 million of debt principal repayment.

Net cash used in financing activities for the three months ended March 31, 2014 consisted of $3.6 million of debt principal repayment partially offset by $1.6 million of proceeds received from the exercise of stock options.

9. SHARES OUTSTANDING

As at March 31, 2015, the Corporation had the following share capital instruments outstanding:

Common shares	223,846,891
Convertible securities	
Stock options outstanding - exercisable and unexercisable	7,765,048
RSUs and PSUs outstanding	2,654,900

As at April 27, 2015, the Corporation had 223,846,891 common shares, 7,712,856 stock options and 2,627,435 restricted share units and performance share units outstanding.

10. 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)	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long-term debt(1)	$ 4,830,003	$ 12,366	$ 32,976	$ 32,976	$ 4,751,685
Interest on long-term debt(1)	1,963,645	274,771	547,803	534,737	606,334
Decommissioning obligation(2)	715,794	1,659	9,850	9,975	694,310
Transportation and storage(3)	3,993,698	139,834	337,675	328,739	3,187,450
Contracts and purchase orders(4)	521,368	218,272	106,347	60,150	136,599
Operating leases(5)	422,666	15,959	54,271	64,366	288,070
	$12,447,174	**$ 662,861**	**$ 1,088,922**	**$ 1,030,943**	**$ 9,664,448**

(1) *This represents the scheduled principal repayment 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 March 31, 2015.*
(2) *This represents the undiscounted future obligation associated with the decommissioning of the Corporation's crude oil, transportation and storage assets.*
(3) *This represents transportation and storage commitments from 2015 to 2037.*
(4) *This represents the future commitment associated with the Corporation's capital program, diluent purchases and other operating and maintenance commitments.*
(5) *This represents the future commitments for the Calgary Corporate office.*

11. NON-GAAP MEASURES

Certain financial measures in this MD&A including: Net marketing activity, Cash flow from (used in) 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 interim consolidated financial statements and Purchased product and storage is presented as a line item on the Interim Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss).

Cash Flow from (Used In) Operations

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

	Three months ended March 31	
($000)	**2015**	**2014**
Net cash provided by (used in) operating activities	**$ (16,942)**	$ 39,049
Add (deduct):		
Net change in non-cash operating working capital items	**(13,488)**	117,763
Decommissioning expenditures	**896**	175
Cash flow from (used in) operations	**$ (29,534)**	$ 156,987

Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP measure which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating earnings (loss) is defined as net earnings (loss) as reported, excluding unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial liabilities, unrealized fair value gains and losses on other assets 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.

	Three months ended March 31	
($000)	**2015**	**2014**
Net loss	**$ (508,307)**	$ (103,441)
Add (deduct):		
Unrealized net loss on foreign exchange(1)	**370,849**	140,601
Unrealized loss (gain) on derivative financial liabilities(2)	**3,531**	(1,627)
Deferred tax expense relating to these adjustments	**9,506**	5,126
Operating earnings (loss)	**$ (124,421)**	$ 40,659

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

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

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 dividing related production revenue, costs and royalties by bitumen sales volumes.

12. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's critical accounting estimates are those estimates having a significant impact on the Corporation's financial position and operations and that require management to make judgments, assumptions and estimates in the application of IFRS. Judgments, assumptions and estimates are based on historical experience and other factors that management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgments, assumptions and estimates may be subject to change.

For a detailed discussion regarding the Corporation's critical accounting policies and estimates please refer to the Corporation's 2014 annual MD&A.

13. TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any related party transactions during the three month periods ended March 31, 2015 and March 31, 2014, other than compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

14. OFF-BALANCE SHEET ARRANGEMENTS

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

15. NEW ACCOUNTING POLICIES

Accounting standards issued but not yet applied

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, 2017, with early adoption permitted. The Corporation is currently assessing the impact of the adoption of IFRS 15 on the Corporation's interim consolidated financial statements.

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 a 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 interim consolidated financial statements.

16. 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 and described in the Corporation's MD&A for the year ended December 31, 2014. 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.

17. 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.

18. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

19. 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 ("SORs"), 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 electrical 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 and foreign exchange 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 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 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 the Corporation 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 and Resources

This document contains references to estimates of the Corporation's reserves and contingent resources. For supplemental information regarding the classification and uncertainties related to MEG's estimated reserves and resources please see "Independent Reserve and Resource Evaluation" in the 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 (used in) 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 the Corporation'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.

20. 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.

21. QUARTERLY SUMMARIES

	2015	2014				2013		
Unaudited	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
FINANCIAL ($000 unless specified)								
Net earnings (loss)[(1)]	**(508,307)**	(150,076)	(100,975)	248,954	(103,441)	(148,182)	115,383	(62,312)
Per share, diluted	**(2.27)**	(0.67)	(0.45)	1.11	(0.46)	(0.67)	0.51	(0.28)
Operating earnings (loss)	**(124,421)**	8,084	87,471	111,139	40,659	(32,685)	56,171	13,612
Per share, diluted	**(0.56)**	0.04	0.39	0.49	0.18	(0.15)	0.25	0.06
Cash flow from (used in) operations	**(29,534)**	134,099	238,659	261,713	156,987	22,648	144,521	79,184
Per share, diluted	**(0.13)**	0.60	1.06	1.16	0.70	0.10	0.64	0.35
Cash capital investment	**80,101**	323,970	291,309	298,727	323,533	366,321	454,589	635,616
Cash, cash equivalents and short-term investments	**470,778**	656,097	776,522	839,870	890,335	1,179,072	647,096	1,203,457
Working capital	**386,130**	525,534	747,928	805,742	877,069	1,045,607	365,676	731,290
Long-term debt[(2)]	**4,775,590**	4,365,502	4,217,536	4,016,257	4,162,209	4,004,575	2,857,740	2,923,382
Shareholders' equity	**4,279,873**	4,768,235	4,894,444	4,970,144	4,705,966	4,788,430	4,919,407	4,771,616
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**48.63**	73.15	97.16	102.99	98.68	97.43	105.83	94.22
C$ equivalent of 1US$ - average	**1.2411**	1.1357	1.0893	1.0905	1.1035	1.0477	1.0385	1.0233
Differential – WTI:WCS ($/bbl)	**18.22**	16.34	22.02	21.87	25.48	33.77	18.15	19.60
Differential – WTI:WCS (%)	**30.2%**	19.7%	20.8%	19.5%	23.4%	33.1%	16.5%	20.3%
Natural gas – AECO ($/mcf)	**2.74**	3.58	4.00	4.70	5.69	3.52	2.42	3.51
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**82,398**	80,349	76,471	68,984	58,643	42,251	34,246	32,144
Bitumen sales – bbls/d	**85,519**	70,116	69,757	70,849	58,089	35,990	32,175	32,175
Steam to oil ratio (SOR)	**2.6**	2.5	2.5	2.4	2.5	2.9	2.5	2.3
Bitumen realization	**25.82**	50.48	65.12	72.75	62.28	38.22	74.33	53.98
Transportation – net	**(4.70)**	(1.82)	(1.09)	(1.80)	(0.67)	(0.51)	(0.20)	(0.17)
Royalties	**(0.80)**	(2.97)	(5.02)	(5.01)	(4.47)	(2.71)	(5.14)	(3.03)
Operating costs – non-energy	**(7.57)**	(6.42)	(7.16)	(9.64)	(9.05)	(8.09)	(9.20)	(10.00)
Operating costs – energy	**(4.07)**	(5.16)	(5.58)	(6.45)	(8.43)	(5.38)	(3.32)	(4.85)
Power revenue	**1.15**	1.45	2.43	1.60	3.85	2.25	3.12	6.00
Cash operating netback	**9.83**	35.56	48.70	51.45	43.51	23.78	59.59	41.93
Power sales price (C$/MWh)	**28.21**	31.67	59.07	40.98	62.26	44.63	75.96	138.96
Power sales (MW/h)	**145**	134	119	115	150	76	59	58
Depletion and depreciation rate per bbl	**15.02**	15.61	15.26	15.30	15.54	15.56	15.54	15.11
COMMON SHARES								
Shares outstanding, end of period (000)	**223,847**	223,847	223,794	223,673	222,575	222,507	222,489	221,829
Volume traded (000)	**57,657**	94,588	30,649	70,199	32,102	33,400	28,403	43,789
Common share price ($)								
High	**24.31**	34.69	40.75	41.29	37.84	36.00	36.69	32.98
Low	**14.84**	13.30	34.00	35.52	29.41	28.60	28.81	25.50
Close (end of period)	**20.46**	19.55	34.38	38.89	37.36	30.61	35.54	28.83

(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) Includes current and long-term portions, as presented on the Consolidated Balance Sheet.

Interim Consolidated Financial Statements

Consolidated Balance Sheet
(Unaudited, expressed in thousands of Canadian dollars)

As at	Note	March 31, 2015	December 31, 2014
Assets			
Current assets			
Cash and cash equivalents	22	**$ 470,778**	$ 656,097
Trade receivables and other	6	**183,291**	177,219
Inventories	7	**64,986**	153,320
		719,055	986,636
Non-current assets			
Property, plant and equipment	8	**8,185,212**	8,195,490
Exploration and evaluation assets	9	**588,357**	588,526
Other intangible assets	10	**85,947**	83,090
Other assets	11	**137,953**	76,366
Total assets		**$ 9,716,524**	$ 9,930,108
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	12	**$ 299,621**	$ 427,910
Current portion of long-term debt	13	**16,488**	15,081
Current portion of provisions and other liabilities	14	**16,816**	18,111
		332,925	461,102
Non-current liabilities			
Long-term debt	13	**4,759,102**	4,350,421
Provisions and other liabilities	14	**194,199**	172,154
Deferred income tax liability		**150,425**	178,196
Total liabilities		**5,436,651**	5,161,873
Commitments and contingencies	26		
Shareholders' equity			
Share capital	15	**4,797,853**	4,797,853
Contributed surplus	15	**167,944**	153,837
Deficit		**(704,977)**	(196,670)
Accumulated other comprehensive income		**19,053**	13,215
Total shareholders' equity		**4,279,873**	4,768,235
Total liabilities and shareholders' equity		**$ 9,716,524**	$ 9,930,108

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

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

		Three months ended March 31	
	Note	**2015**	**2014**
Petroleum revenue, net of royalties	16	**$ 455,682**	$ 650,052
Other revenue	17	**11,313**	29,510
		466,995	679,562
Diluent and transportation	18	**295,710**	289,098
Purchased product and storage	19	**12,107**	71,662
Operating expenses		**89,598**	91,390
Depletion and depreciation	8,10	**115,571**	81,244
General and administrative		**33,306**	26,375
Stock-based compensation	15	**12,530**	12,622
Research and development		**1,172**	991
		559,994	573,382
Revenues less expenses		**(92,999)**	106,180
Other income (expense)			
Interest and other income		**964**	3,260
Foreign exchange loss, net	20	**(378,079)**	(143,244)
Net finance expense	21	**(65,967)**	(46,761)
		(443,082)	(186,745)
Loss before income taxes		**(536,081)**	(80,565)
Deferred income tax expense (recovery)		**(27,774)**	22,876
Net loss		**(508,307)**	(103,441)
Other comprehensive income, net of tax			
Items that may be reclassified to profit or loss:			
Foreign currency translation adjustment		**5,838**	3,702
Comprehensive loss for the period		**$ (502,469)**	$ (99,739)

Net loss per common share			
Basic	23	**$ (2.27)**	$ (0.46)
Diluted	23	**$ (2.27)**	$ (0.46)

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

Consolidated Statement of Changes in Shareholders' Equity
(Unaudited, expressed in thousands of Canadian dollars)

	Note	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance at December 31, 2014		**$ 4,797,853**	**$ 153,837**	**$ (196,670)**	**$ 13,215**	**$ 4,768,235**
Stock-based compensation	15	**-**	**14,107**	**-**	**-**	**14,107**
Net loss		**-**	**-**	**(508,307)**	**-**	**(508,307)**
Other comprehensive income		**-**	**-**	**-**	**5,838**	**5,838**
Balance at March 31, 2015		**$ 4,797,853**	**$ 167,944**	**$ (704,977)**	**$ 19,053**	**$ 4,279,873**
Balance at December 31, 2013		$ 4,751,374	$ 126,666	$ (92,493)	$ 2,883	$ 4,788,430
Stock options exercised		2,130	(493)	-	-	1,637
Stock-based compensation		-	15,638	-	-	15,638
RSUs vested and released		80	(80)	-	-	-
Net loss		-	-	(103,441)	-	(103,441)
Other comprehensive income		-	-	-	3,702	3,702
Balance at March 31, 2014		$ 4,753,584	$ 141,731	$ (195,934)	$ 6,585	$ 4,705,966

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

Consolidated Statement of Cash Flow
(Unaudited, expressed in thousands of Canadian dollars)

		Three months ended March 31	
	Note	**2015**	**2014**
Cash provided by (used in):			
Operating activities			
Net loss		**$ (508,307)**	$ (103,441)
Adjustments for:			
Depletion and depreciation	8,10	**115,571**	81,244
Stock-based compensation	15	**12,530**	12,622
Unrealized loss on foreign exchange	20	**370,849**	140,601
Unrealized loss (gain) on derivative financial liabilities	21	**3,531**	(1,627)
Deferred income tax expense (recovery)		**(27,774)**	22,876
Amortization of debt issue costs	11,13	**2,885**	2,580
Decommissioning expenditures	14	**(896)**	(175)
Other		**1,181**	2,132
Net change in non-cash operating working capital items	22	**13,488**	(117,763)
Net cash provided by (used in) operating activities		**(16,942)**	39,049
Investing activities			
Capital investments			
Property, plant and equipment	8	**(91,590)**	(337,040)
Exploration and evaluation	9	**(247)**	(2,588)
Other intangible assets	10	**(4,267)**	(3,375)
Other		**1,941**	1,302
Net change in non-cash investing working capital items	22	**(111,647)**	(3,010)
Net cash provided by (used in) investing activities		**(205,810)**	(344,711)
Financing activities			
Issue of shares	15	**-**	1,637
Repayment of long-term debt	13	**(4,124)**	(3,596)
Net cash provided by (used in) financing activities		**(4,124)**	(1,959)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	20	**41,557**	18,884
Change in cash and cash equivalents		**(185,319)**	(288,737)
Cash and cash equivalents, beginning of period		**656,097**	1,179,072
Cash and cash equivalents, end of period		**$ 470,778**	$ 890,335

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

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange ("TSX") under the symbol "MEG". The Corporation owns a 100% interest in over 900 square miles of oil sands leases in the southern Athabasca oil sands region of northern Alberta and is primarily engaged in a steam assisted gravity drainage oil sands development at its 80 section Christina Lake Regional Project ("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 the Access Pipeline, the Corporation owns the Stonefell Terminal, located near Edmonton, Alberta, which offers 900,000 barrels of terminalling and storage capacity. The Stonefell Terminal is connected to the Access Pipeline and is also connected by pipeline to a third party rail-loading terminal. The corporate office is located at 520 - 3rd Avenue S.W., Calgary, Alberta, Canada.

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements (“interim consolidated financial statements”) were prepared using the same accounting policies and methods as those used in the Corporation’s audited consolidated financial statements for the year ended December 31, 2014. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting (“IAS 34”). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board ("IASB"), have been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation’s accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 3 of the Corporation’s audited consolidated financial statements for the year ended December 31, 2014. These interim consolidated financial statements should be read in conjunction with the Corporation’s audited consolidated financial statements for the year ended December 31, 2014, which are included in the Corporation’s 2014 annual report.

These interim consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation’s functional currency. 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.

These interim consolidated financial statements were approved by the Corporation’s Audit Committee effective May 6, 2015.

3. CHANGE IN ACCOUNTING POLICIES

Accounting standards issued but not yet applied

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, 2017, 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 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.

4. PRINCIPLES OF CONSOLIDATION

The interim consolidated financial statements of the Corporation comprise the Corporation and its wholly-owned subsidiary, MEG Energy (U.S.) Inc. All intercompany transactions and balances 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 interim consolidated financial statements in proportion to the Corporation's share of assets, liabilities, revenues and expenses.

5. FINANCIAL INSTRUMENTS AND DERIVATIVE FINANCIAL LIABILITIES

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 March 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, derivative financial liabilities and long-term debt:

			Fair value measurements using		
As at March 31, 2015	**Carrying amount**	**Fair value**	**Quoted prices in active markets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
Recurring measurements:					
Financial assets					
ARS (Note 11)	**$ 3,180**	**$ 3,180**	**$ -**	**$ 3,180**	**$ -**
Financial liabilities					
Long-term debt[(1)] (Note 13)	**4,830,003**	**4,531,218**	**4,531,218**	**-**	**-**
Derivative financial liabilities (Note 14)	**33,044**	**33,044**	**-**	**33,044**	**-**

			Fair value measurements using		
As at December 31, 2014	**Carrying amount**	**Fair value**	**Quoted prices in active markets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
Recurring measurements:					
Financial assets					
ARS (Note 11)	$ 2,908	$ 2,908	$ -	$ 2,908	$ -
Financial liabilities					
Long-term debt[(1)] (Note 13)	4,421,721	4,075,233	4,075,233	-	-
Derivative financial liabilities (Note 14)	29,511	29,511	-	29,511	-

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

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

The fair value of long-term debt is derived using quoted prices in an active market.

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

The estimated fair value of the ARS is 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.

Level 3 measurements consist of financial instruments with a fair value that is determined by reference to prices with significant unobservable inputs. As at March 31, 2015, the Corporation does 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. There were no transfers between levels of the fair value hierarchy during the period ended March 31, 2015.

(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$1.3 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	Apr 2015-Sept 2016	4.436%	3 month LIBOR[1]
US$150 million	December 31, 2011	Apr 2015-Sept 2016	4.376%	3 month LIBOR[1]
US$150 million	January 12, 2012	Apr 2015-Sept 2016	4.302%	3 month LIBOR[1]
US$148 million	January 27, 2012	Apr 2015-Sept 2016	4.218%	3 month LIBOR[1]

[1] *London Interbank Offered Rate*

6. TRADE RECEIVABLES AND OTHER

	March 31, 2015	December 31, 2014
Trade receivables	**$ 164,536**	$ 167,559
Deposits and advances	**14,437**	5,344
Current portion of deferred financing costs	**4,318**	4,316
	$ 183,291	$ 177,219

7. INVENTORIES

	March 31, 2015	December 31, 2014
Diluent	**$ 28,557**	$ 83,001
Bitumen blend	**34,333**	68,273
Materials and supplies	**2,096**	2,046
	$ 64,986	$ 153,320

The Corporation has entered into agreements to transport bitumen blend and diluent on third-party owned pipelines and is required to supply linefill for these pipelines. During the first quarter of 2015, the Corporation transferred $40.7 million of diluent and $11.5 million of bitumen blend from inventories to long-term pipeline linefill (Note 11) to meet these obligations.

During the period ended March 31, 2015, a total of $257.0 million in inventory product costs were charged to earnings through diluent and transportation expense (period ended March 31, 2014 - $276.2 million).

8. 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 11)	-	(12,381)	-	(12,381)
Balance as at December 31, 2014	$ 7,539,369	$ 1,560,314	$ 47,117	$ 9,146,800
Additions	78,650	12,910	1,904	93,464
Change in decommissioning liabilities	16,601	768	-	17,369
Transfer to other assets (Note 11)	-	(6,938)	-	(6,938)
Balance as at March 31, 2015	**$ 7,634,620**	**$ 1,567,054**	**$ 49,021**	**$ 9,250,695**
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 period	105,501	7,247	1,425	114,173
Balance as at March 31, 2015	**$ 989,224**	**$ 58,360**	**$ 17,899**	**$ 1,065,483**
Carrying Amounts				
Balance as at December 31, 2014	$ 6,655,646	$ 1,509,201	$ 30,643	$ 8,195,490
Balance as at March 31, 2015	**$ 6,645,396**	**$ 1,508,694**	**$ 31,122**	**$ 8,185,212**

During the three months ended March 31, 2015, the Corporation capitalized $6.3 million of general and administrative costs (three months ended March 31, 2014 - $8.8 million), and $1.6 million of stock-based compensation costs (three months ended March 31, 2014 - $3.0 million), relating to oil sands exploration and development activities. In addition, $16.0 million of interest and finance charges related to the development of capital projects were capitalized during the three months ended March 31, 2015 (three months ended March 31, 2014 - $19.5 million). As at March 31, 2015, $882.2 million of assets under construction were included within property, plant and equipment (December 31, 2014 - $864.7 million). Assets under construction are not subject to depletion and depreciation. As of March 31, 2015, no impairment has been recognized on these assets.

9. 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		247
Change in decommissioning liabilities		(416)
Balance as at March 31, 2015	**$**	**588,357**

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 of March 31, 2015, no impairment has been recognized on these assets. During the three months ended March 31, 2015, the Corporation did not capitalize any interest and finance charges related to exploration and evaluation assets (three months ended March 31, 2014 - $0.3 million).

10. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2013	$	66,209
Additions		23,571
Balance as at December 31, 2014	$	89,780
Additions		4,267
Balance as at March 31, 2015	**$**	**94,047**

Accumulated depreciation		
Balance as at December 31, 2013	$	3,004
Depreciation		3,686
Balance as at December 31, 2014	$	6,690
Depreciation		1,410
Balance as at March 31, 2015	**$**	**8,100**

Carrying Amounts		
Balance as at December 31, 2014	$	83,090
Balance as at March 31, 2015	**$**	**85,947**

At March 31, 2015, other intangible assets include $63.3 million invested to maintain the right to participate in a potential pipeline project and $22.6 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 March 31, 2015, no impairment has been recognized on these assets.

11. OTHER ASSETS

	March 31, 2015	December 31, 2014
Long-term pipeline linefill[a]	**$ 119,299**	$ 56,900
ARS[b]	**3,180**	2,908
Deferred financing costs[c]	**19,792**	20,874
	142,271	80,682
Less current portion of deferred financing costs	**(4,318)**	(4,316)
	$ 137,953	$ 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 first quarter of 2015, the Corporation transferred $6.9 million of bitumen blend from property, plant and equipment to long-term pipeline linefill. 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. The linefill is classified as a long-term asset as these transportation contracts extend beyond the year 2025. As of March 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. 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 facilities are deferred and amortized over the term of the credit facilities.

12. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	March 31, 2015	December 31, 2014
Trade payables	**$ 42,738**	$ 10,810
Accrued liabilities	**238,897**	355,564
Interest payable	**17,986**	61,536
	$ 299,621	$ 427,910

13. LONG-TERM DEBT

	March 31, 2015	December 31, 2014
Senior secured term loan (March 31, 2015 – US$1.258 billion; December 31, 2014 – US$1.262 billion)[(a)]	**$ 1,595,838**	$ 1,463,466
6.5% senior unsecured notes (US$750 million)[(b)]	**951,225**	870,075
6.375% senior unsecured notes (US$800 million)[(c)]	**1,014,640**	928,080
7.0% senior unsecured notes (US$1.0 billion)[(d)]	**1,268,300**	1,160,100
	4,830,003	4,421,721
Less current portion of senior secured term loan	**(16,488)**	(15,081)
Less unamortized financial derivative liability discount	**(16,748)**	(17,514)
Less unamortized deferred debt issue costs	**(37,665)**	(38,705)
	$ 4,759,102	$ 4,350,421

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2683 (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.

(a) The senior secured credit facilities are comprised of a US$1.3 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. Interest is paid quarterly.

    The US$2.5 billion senior secured revolving credit facility matures on November 5, 2019. As at March 31, 2015, the revolving credit facility remains undrawn.

    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 will not consume capacity of the revolving credit facility. As at March 31, 2015, letters of credit of US$157.5 million had been issued under this facility (December 31, 2014 - US$164.8 million).

(b) The US$750.0 million in aggregate principal amount of 6.5% Senior Unsecured Notes have 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) The US$800.0 million in aggregate principal amount of 6.375% Senior Unsecured Notes have 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) The US$1.0 billion in aggregate principal amount of 7.0% Senior Unsecured Notes have a maturity date of March 31, 2024. Interest is paid semi-annually on March 31 and September 30. No principal payments are required until March 31, 2024.

The Corporation has deferred the associated remaining debt issue costs of $37.7 million and is amortizing these costs over the lives of the debt utilizing the effective interest method (December 31, 2014 – $38.7 million).

14. PROVISIONS AND OTHER LIABILITIES

	March 31, 2015	December 31, 2014
Derivative financial liabilities[(a)]	**$ 33,044**	$ 29,511
Decommissioning provision[(b)]	**173,751**	156,382
Deferred lease inducements[(c)]	**4,220**	4,372
Provisions and other liabilities	**211,015**	190,265
Less current portion	**(16,816)**	(18,111)
Non-current portion	**$ 194,199**	$ 172,154

(a) Derivative financial liabilities:

	March 31, 2015	December 31, 2014
1% interest rate floor	**$ 25,934**	$ 20,844
Interest rate swaps	**7,110**	8,667
Derivative financial liabilities	**33,044**	29,511
Less current portion	**(14,419)**	(15,538)
Non-current portion	**$ 18,625**	$ 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 March 31, 2015, the Corporation had entered into interest rate swaps on US$748.0 million (Note 5(b)) which expire 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.

(b) The following table presents the decommissioning provision associated with the reclamation and abandonment of crude oil, transportation and storage assets:

	March 31, 2015	December 31, 2014
Decommissioning provision, beginning of year	**$ 156,382**	$ 108,695
Changes in estimated future cash flows	**(1,351)**	20,406
Changes in discount rates	**14,718**	13,798
Liabilities incurred	**3,586**	10,841
Liabilities settled	**(896)**	(1,893)
Accretion	**1,312**	4,535
Decommissioning provision, end of period	**173,751**	156,382
Less current portion	**(1,659)**	(1,835)
Non-current portion	**$ 172,092**	$ 154,547

The total decommissioning provision is based on the estimated costs to reclaim and abandon the Corporation's crude oil, transportation and storage assets and the estimated timing of the costs to be incurred in future years. The Corporation has estimated the net present value of the decommissioning obligations to be $173.8 million as at March 31, 2015 (December 31, 2014 - $156.4 million) based on an undiscounted total future liability of $715.8 million (December 31, 2014 - $707.8 million) and a credit-adjusted risk-free rate of 5.4% (December 31, 2014 – 6.0%). This obligation is estimated to be settled in periods up to the year 2064.

(c) Deferred lease inducements:

	March 31, 2015	December 31, 2014
Deferred lease inducements	**$ 4,220**	$ 4,372
Less current portion	**(738)**	(738)
Non-current portion	**$ 3,482**	$ 3,634

Leasehold inducements were received when the Corporation entered into the corporate office lease. These inducements are recognized as a deferred liability and amortized through general and administrative expense over the life of the lease.

15. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

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

	Three months ended March 31, 2015		Year ended December 31, 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	**-**	**-**	927,351	31,814
Balance, end of period	**223,846,891**	**$ 4,797,853**	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 after three years and expire seven years after the grant date.

Three months ended March 31, 2015	**Stock options**	**Weighted average exercise price per share**
Outstanding, beginning of year	**7,865,788**	**$ 34.87**
Granted	**26,451**	**21.07**
Forfeited	**(77,191)**	**34.86**
Expired	**(50,000)**	**41.00**
Outstanding, end of period	**7,765,048**	**$ 34.79**

(d) Restricted share units outstanding 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.

Three Months ended March 31, 2015	
Outstanding, beginning of year	**2,745,439**
Forfeited	**(90,539)**
Outstanding, end of period	**2,654,900**

(e) Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of Deferred Share Units ("DSUs") to directors of the Corporation. At March 31, 2015, there were 17,281 DSUs outstanding (December 31, 2014 – 17,281).

(f) Contributed surplus:

Three months ended March 31, 2015	
Balance, beginning of year	**$ 153,837**
Stock-based compensation - expensed	**12,530**
Stock-based compensation - capitalized	**1,577**
Balance, end of period	**$ 167,944**

16. PETROLEUM REVENUE, NET OF ROYALTIES

	Three months ended March 31	
	2015	**2014**
Petroleum revenue:		
Proprietary	**$ 455,753**	$ 601,828
Third party [a]	**6,079**	71,607
	461,832	673,435
Royalties	**(6,150)**	(23,383)
Petroleum revenue, net of royalties	**$ 455,682**	$ 650,052

(a) 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" (Note 19).

17. OTHER REVENUE

	Three months ended March 31	
	2015	**2014**
Power revenue	**$ 8,819**	$ 20,131
Transportation revenue	**2,494**	9,379
Other revenue	**$ 11,313**	$ 29,510

18. DILUENT AND TRANSPORTATION

	Three months ended March 31	
	2015	**2014**
Diluent	**$ 257,048**	$ 276,208
Transportation	**38,662**	12,890
Diluent and transportation	**$ 295,710**	$ 289,098

19. PURCHASED PRODUCT AND STORAGE

	Three months ended March 31	
	2015	**2014**
Purchased product and storage	**$ 12,107**	$ 71,662

The Corporation purchases crude oil products from third parties for marketing-related activities. The revenue associated with these purchases is included in the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss) under the caption "Petroleum revenue, net of royalties" (Note 16).

20. FOREIGN EXCHANGE LOSS, NET

	Three months ended March 31	
	2015	**2014**
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ (412,406)**	$ (159,485)
US$ denominated cash and cash equivalents	**41,557**	18,884
Unrealized net loss on foreign exchange	**(370,849)**	(140,601)
Realized loss on foreign exchange	**(7,230)**	(2,643)
Foreign exchange loss, net	**$ (378,079)**	$ (143,244)

21. NET FINANCE EXPENSE

	Three months ended March 31	
	2015	**2014**
Total interest expense	**$ 75,726**	$ 65,700
Less capitalized interest	**(16,003)**	(19,470)
Net interest expense	**59,723**	46,230
Accretion on decommissioning provision	**1,312**	1,037
Unrealized fair value loss (gain) on embedded derivative liabilities	**5,087**	(1,110)
Unrealized fair value gain on interest rate swaps	**(1,556)**	(517)
Realized loss on interest rate swaps	**1,401**	1,121
Net finance expense	**$ 65,967**	$ 46,761

22. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended March 31	
	2015	**2014**
Changes in non-cash working capital		
Operating activities:		
Trade receivables and other	**$ (6,070)**	$ (90,178)
Inventories[(a)]	**36,200**	(17,079)
Accounts payable and accrued liabilities	**(16,642)**	(10,506)
Change in operating non-cash working capital	**$ 13,488**	$ (117,763)
Investing activities:		
Accounts payable and accrued liabilities	**$ (111,647)**	$ (3,010)
Change in investing non-cash working capital	**$ (111,647)**	$ (3,010)
Change in total non-cash working capital	**$ (98,159)**	$ (120,773)
Cash and cash equivalents:[(b)]		
Cash	**$ 279,910**	$ 486,227
Cash equivalents	**190,868**	404,108
	$ 470,778	$ 890,335

(a) The March 31, 2015 amount excludes a non-cash decrease in inventory of $52.1 million (March 31, 2014 –$0.2 million). The Corporation has entered into agreements to transport bitumen blend and diluent on third-party owned pipelines and is required to supply linefill for these pipelines. The Corporation has fulfilled these obligations through the transfer of bitumen blend and diluent from inventories (Note 7 and 11).

(b) As at March 31, 2015, C$325.1 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars. (March 31, 2014 - C$325.2 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$1.2683 (March 31, 2014 - US$1 = C$1.1053).

23. NET LOSS PER COMMON SHARE

	Three months ended March 31			
		2015		**2014**
Net loss	**$**	**(508,307)**	$	(103,441)
Weighted average common shares outstanding		**223,889,936**		222,544,253
Dilutive effect of stock options, RSUs and PSUs[(a)]		**-**		-
Weighted average common shares outstanding – diluted		**223,889,936**		222,544,253
Net loss per share, basic	**$**	**(2.27)**	$	(0.46)
Net loss per share, diluted	**$**	**(2.27)**	$	(0.46)

(a) For the three months ended March 31, 2015 and March 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 three months ended March 31, 2015, the dilutive effect of stock options, RSUs and PSUs would have been 885,298 weighted average common shares (three months ended March 31, 2014 – 1,574,839).

24. GEOGRAPHICAL DISCLOSURE

As at March 31, 2015, the Corporation had non-current assets related to operations in the United States of $92.6 million (December 31, 2014 - $44.1 million). For the three months ended March 31, 2015, petroleum revenue related to operations in the United States was $108.9 million, (three months ended March 31, 2014 - $52.5 million).

25. 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 interim consolidated financial statements. As at March 31, 2015, the Corporation's proportionate interest in the joint operation's working capital balances was $13.8 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 $3.9 million and capital commitments of $1.9 million related to the joint operation are included within "Commitments" presented within Note 26.

26. COMMITMENTS AND CONTINGENCIES

(a) Commitments

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

Operating:

	2015	2016	2017	2018	2019	Thereafter
Office lease rentals	$ 11,894	$ 16,261	$ 34,036	$ 32,156	$ 32,199	$ 296,120
Diluent purchases	132,168	55,876	19,443	19,443	19,443	74,576
Pipeline transportation and storage	97,783	168,204	169,445	168,308	162,387	3,227,571
Other commitments	11,955	15,138	13,729	12,127	9,735	69,317
Commitments	**$ 253,800**	**$ 255,479**	**$ 236,653**	**$ 232,034**	**$ 223,764**	**$ 3,667,584**

Capital:

As part of normal operations, the Corporation has entered into a total of $68.4 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.