FOURTH QUARTER 2015

Report to Shareholders for the period ended December 31, 2015

MEG Energy Corp. reported fourth quarter and full-year 2015 operating and financial results on February 4, 2016. Highlights include:

- Record quarterly production volumes of 83,514 barrels per day (bpd) contributing to record annual production of 80,025 bpd, a 12% increase year-over-year, while the 2015 capital budget was significantly reduced;

- Record-low net and non-energy operating costs for both the fourth quarter and the full year of 2015;

- Year-end cash and cash equivalents of $408 million and an undrawn credit facility of US$2.5 billion;

- An approximately 50% reduction in planned 2016 capital spending to $170 million from previous guidance of $328 million, while still maintaining production guidance for the full year.

MEG's fourth quarter 2015 production was a record 83,514 bpd, compared to 80,349 bpd for the fourth quarter of 2014. Full-year 2015 production increased 12% from 2014 totals, meeting targets and reflecting the ongoing efficiency gains associated with MEG's proprietary eMSAGP reservoir technology.

MEG established record-low net and non-energy operating costs for both the fourth quarter and the full year of 2015. Net operating costs were recorded at $8.52 per barrel in the fourth quarter of 2015 with net annual operating costs of $9.39 per barrel. At $5.66 per barrel, fourth quarter non-energy operating costs supported record-low annual non-energy operating costs of $6.54 per barrel, well below the company's 2015 revised guidance. Lower operating costs on both a quarterly and annual basis are reflective of higher production volumes and efficiency gains, as well as lower input prices for natural gas.

"Our operating performance throughout 2015 met or exceeded our targets," said Bill McCaffrey, President and Chief Executive Officer. "Our low cost structure is enabling MEG to weather the low commodity price environment seen over the past year."

MEG recorded cash flow used in operations of $44 million for the fourth quarter of 2015 compared to cash flow from operations of $134 million for the same period in 2014. Cash flow from operations decreased primarily due to lower price realizations and higher transportation and interest costs, partially offset by higher sales volumes and lower royalty expenses. Full year 2015 cash flow from operations remained positive at $49 million.

The company recorded a fourth quarter 2015 operating loss of $140 million compared to operating earnings of $8 million for the same period in 2014. The difference in operating earnings reflects the same factors impacting cash flow, as well as an increase in depletion and depreciation expense.

Capital investment and financial liquidity

MEG's capital investment in 2015 totalled $257 million, which was 23% below the capital budget after adjusting for capitalized turnaround costs. This reduced spending was a result of ongoing gains in capital efficiency.

In December 2015, MEG announced a 2016 annual capital program of $328 million. This has been revised downward by approximately 50% to $170 million. The reduction was achieved through the deferral of some previously planned growth capital spending, as well as efficiency enhancements to reservoir performance that has resulted in higher well productivity. Productivity improvements have enabled MEG to reduce planned 2016 sustaining and maintenance requirements to below $5 per barrel from previous estimates of $7 to $8 per barrel.

The reduction in 2016 capital spending is not expected to impact MEG's production guidance of 80,000 to 83,000 bpd and non-energy operating costs of $6.75 to $7.75 per barrel, although the company maintains the flexibility to temporarily defer production if warranted by market conditions.

The monetization of MEG's 50% holding in the Access Pipeline continues to be a key priority. The company is working diligently to complete this process, while ensuring the transaction is in the long-term interest of MEG's shareholders.

"MEG entered 2016 with more than $400 million in cash and an undrawn US$2.5 billion credit facility," said McCaffrey. "With significant liquidity and low operating costs, we are well positioned to reduce the impact of the current low-price environment."

OPERATIONAL AND FINANCIAL HIGHLIGHTS

As a result of the ongoing global imbalance between supply and demand for crude oil, the Corporation's operating and financial results for the fourth quarter of 2015 continued to be impacted by the low commodity price environment. The C$/bbl WTI price for the fourth quarter of 2015 decreased 32% compared to the same period in 2014.

In addition, the value of the Canadian dollar relative to the U.S. dollar declined 3% in the fourth quarter of 2015. From December 31, 2014, the value of the Canadian dollar relative to the U.S. dollar has decreased 19%. As the value of the Canadian dollar weakens, the translated value of the Corporation's U.S. dollar denominated debt and related interest expense increases.

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

	Year ended December 31		2015				2014			
($ millions, except as indicated)	**2015**	**2014**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Bitumen production - bbls/d	**80,025**	71,186	**83,514**	82,768	71,376	82,398	80,349	76,471	68,984	58,643
Bitumen realization - $/bbl	**30.63**	62.67	**23.17**	31.03	44.54	25.82	50.48	65.12	72.75	62.28
Net operating costs - $/bbl(1)	**9.39**	12.06	**8.52**	9.10	9.43	10.49	10.13	10.31	14.49	13.63
Non-energy operating costs - $/bbl	**6.54**	8.02	**5.66**	5.98	7.01	7.57	6.42	7.16	9.64	9.05
Cash operating netback - $/bbl(2)	**15.72**	44.87	**9.05**	16.41	29.64	9.83	35.56	48.70	51.45	43.51
Cash flow from (used in) operations(3)	**49**	791	**(44)**	24	99	(30)	134	239	262	157
Per share, diluted(3)	**0.22**	3.52	**(0.20)**	0.11	0.44	(0.13)	0.60	1.06	1.16	0.70
Operating earnings (loss)(3)	**(374)**	247	**(140)**	(87)	(23)	(124)	8	87	111	41
Per share, diluted(3)	**(1.67)**	1.10	**(0.62)**	(0.39)	(0.10)	(0.56)	0.04	0.39	0.49	0.18
Revenue (4)	**1,926**	2,830	**445**	460	555	467	615	706	829	680
Net earnings (loss)(5)	**(1,170)**	(106)	**(297)**	(428)	63	(508)	(150)	(101)	249	(103)
Per share, basic	**(5.21)**	(0.47)	**(1.32)**	(1.90)	0.28	(2.27)	(0.67)	(0.45)	1.12	(0.46)
Per share, diluted	**(5.21)**	(0.47)	**(1.32)**	(1.90)	0.28	(2.27)	(0.67)	(0.45)	1.11	(0.46)
Total cash capital investment(6)	**257**	1,238	**54**	32	90	80	324	291	299	324
Cash and cash equivalents	**408**	656	**408**	351	438	471	656	777	840	890
Long-term debt(7)	**5,190**	4,350	**5,190**	5,024	4,678	4,759	4,350	4,203	4,002	4,148

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

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

(3) *Cash flow from (used in) operations, Operating earnings (loss), and the related per share amounts do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. For the three months and years ended December 31, 2015 and December 31, 2014, the non-GAAP measure of cash flow from (used in) operations is reconciled to net cash provided by operating activities and the non-GAAP measure of operating earnings (loss) is reconciled to net loss in accordance with IFRS under the heading "NON-GAAP MEASURES" and discussed further in the "ADVISORY" section.*

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

(5) Includes a net unrealized foreign exchange loss of $159.0 million and $785.3 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents for the three months and year ended December 31, 2015, respectively. The net loss for the three months and year ended December 31, 2014 include a net unrealized foreign exchange loss of $139.0 million and $333.1 million, respectively.

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

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

(8) Totals may not add due to rounding.

Bitumen Production

Bitumen production for the three months ended December 31, 2015 averaged 83,514 bbls/d compared to 80,349 bbls/d for the three months ended December 31, 2014. Bitumen production for the year ended December 31, 2015 averaged 80,025 bbls/d compared to 71,186 bbls/d for the year ended December 31, 2014. The increase in production volumes is primarily due to efficiency gains associated with RISER at the Christina Lake Project. In 2012, the Corporation announced the RISER initiative, which is designed to increase production from existing assets at lower capital and operating costs using a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including debottlenecking and expansions (collectively, "RISER"). The implementation of the RISER initiative has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production to sustain current production levels. These increases in production were partially offset by a reduction in bitumen volumes as a result of a planned turnaround in the second quarter of 2015, which was longer in duration and had a greater impact on production volumes than the turnaround for the same period in 2014. In addition, forest fires near the Christina Lake Project extended the duration of time required to complete the 2015 turnaround. During 2014, MEG successfully ramped up Phase 2B and in combination with the success achieved from applying RISER to Phases 1 and 2, increased average bitumen production from 58,643 bbls/d in the first quarter of 2014 to 80,349 bbls/day in the fourth quarter of 2014.

Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary petroleum revenue ("blend sales revenue"), net of the cost of diluent, expressed on a per barrel basis. Blend sales revenue represents MEG's revenue from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). AWB is comprised of bitumen produced at the Christina Lake region blended with purchased diluent. The cost of blending is impacted by the amount of diluent required and the Corporation's cost of purchasing and transporting diluent. A portion of the cost of diluent is effectively recovered in the sales price of the blended product. The cost of diluent is also impacted by Canadian and U.S. benchmark pricing, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar.

For the three months ended December 31, 2015, average bitumen realization decreased to $23.17 per barrel compared to $50.48 per barrel for the three months ended December 31, 2014. For the year ended December 31, 2015, average bitumen realization decreased to $30.63 per barrel compared to $62.67 per barrel for the year ended December 31, 2014. The decrease in bitumen realization is primarily a result of the significant decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue and higher relative pricing per barrel for purchased diluent.

The C$/bbl WTI price averaged $56.32 per barrel during the three months ended December 31, 2015 compared to $83.08 per barrel during the three months ended December 31, 2014. The WTI:WCS differential widened to an average of 34.4% for the three months ended December 31, 2015 compared to 19.7% for the three months ended December 31, 2014. The C$/bbl WTI price averaged $62.40 per barrel during the year ended December 31, 2015 compared to $102.74 per barrel during the year ended December 31, 2014. The WTI:WCS differential widened to an average of 27.7% for the year ended December 31, 2015 compared to 21.1% for the year ended December 31, 2014.

Net Operating Costs

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

Net operating costs for the three months ended December 31, 2015 averaged $8.52 per barrel compared to $10.13 per barrel for the three months ended December 31, 2014. The decrease in net operating costs is attributable to a per barrel decrease in energy and non-energy operating costs, partially offset by a decrease in power revenue.

- Energy operating costs decreased to $3.58 per barrel for the three months ended December 31, 2015 compared to $5.16 per barrel for the same period in 2014. The Corporation's energy costs decreased primarily as a result of the decline in natural gas prices, which decreased to an average of $2.94 per mcf for the three months ended December 31, 2015 compared to $3.50 per mcf for the same period in 2014.
- Non-energy operating costs decreased to $5.66 per barrel for the three months ended December 31, 2015 compared to $6.42 per barrel for the same period in 2014. The per barrel decrease is primarily the result of holding absolute costs relatively constant during a period of increasing sales volumes, as these costs are now spread over a greater number of barrels.
- Power revenue decreased to $0.72 per barrel for the three months ended December 31, 2015 compared to $1.45 per barrel for the same period in 2014. The decrease in power revenue is primarily due to a decrease in the Corporation's realized power price. The Corporation's realized power price during the three months ended December 31, 2015 decreased to $19.67 per megawatt hour compared to $31.67 per megawatt hour for the same period in 2014. Power revenue had the effect of offsetting 20% of energy operating costs during the three months ended December 31, 2015 compared to offsetting 28% of energy operating costs during the same period in 2014.

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

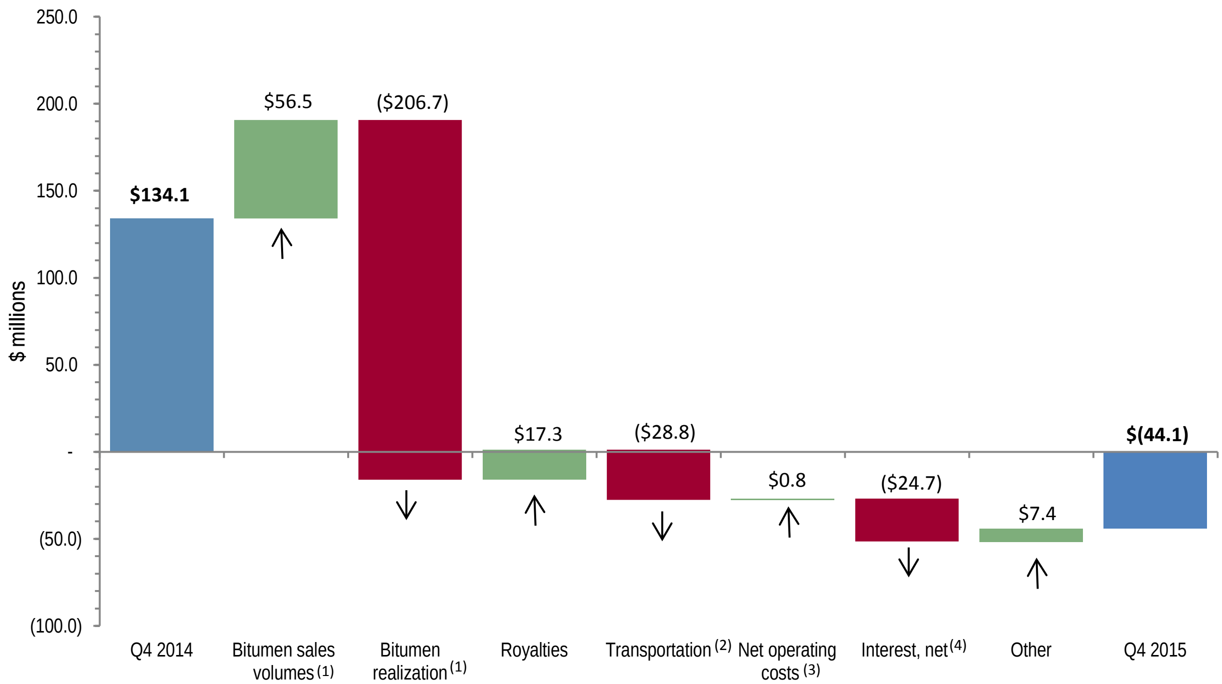
- Energy operating costs decreased to $3.84 per barrel for the year ended December 31, 2015 compared to $6.30 per barrel for the same period in 2014. The Corporation's energy operating costs decreased primarily as a result of the decline in natural gas prices, which decreased to an average of $3.11 per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

- Non-energy operating costs decreased to $6.54 per barrel for the year ended December 31, 2015 compared to $8.02 per barrel for the same period in 2014. Non-energy operating costs for 2014 include $0.51 per barrel for annual inspection and maintenance activities at the Christina Lake facilities. The decrease in non-energy operating costs is primarily the result of efficiency gains and a continued focus on cost management and holding absolute costs relatively constant during a period of increasing sales volumes, as these costs are now spread over a greater number of barrels. Consistent with the Corporation's capitalization policy, the 2015 turnaround costs have been capitalized, as the work performed will benefit future years of operations. As a result, the cost of the 2015 turnaround is treated as a component of capital investment and will be depreciated on a straight line basis over the period to the next turnaround.
- Power revenue decreased to $0.99 per barrel for the year ended December 31, 2015 compared to $2.26 per barrel for the same period in 2014. The decrease is primarily due to a decrease in the Corporation's realized power price. The Corporation's realized power price during the year ended December 31, 2015 decreased to $27.48 per megawatt hour compared to $48.83 per megawatt hour for the same period in 2014. Power revenue had the effect of offsetting 26% of energy operating costs during the year ended December 31, 2015 compared to offsetting 36% of energy operating costs during the same period in 2014.

Cash Operating Netback

Cash operating netback for the three months ended December 31, 2015 was $9.05 per barrel compared to $35.56 per barrel for the three months ended December 31, 2014. Cash operating netback for the year ended December 31, 2015 was $15.72 per barrel compared to $44.87 per barrel for the year ended December 31, 2014. The decrease in the cash operating netback is primarily due to a decrease in bitumen realization as a result of the significant decline of U.S. crude oil benchmark pricing.

Cash Flow from (Used in) Operations – Three Months Ended December 31, 2015



(1) *Net of diluent.*

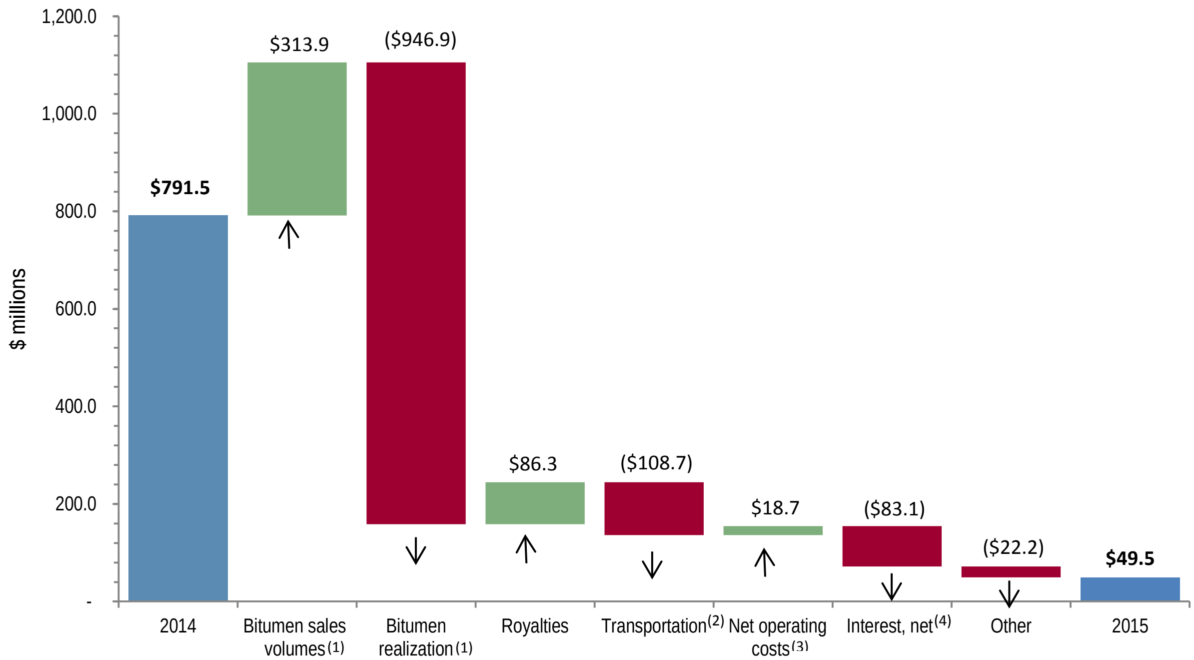
(2) *Defined as transportation expense less transportation revenue.*

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

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

Cash flow used in operations was $44.1 million for the three months ended December 31, 2015 compared to cash flow from operations of $134.1 million for the three months ended December 31, 2014. Cash flow from operations decreased primarily due to lower bitumen realization, higher transportation and higher interest costs, partially offset by an increase in bitumen sales volumes and lower royalties. The decrease in bitumen realization and decrease in royalties is directly correlated to the significant decline of U.S. crude oil benchmark pricing. Transportation expense increased primarily due to the cost of transporting blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, which commenced operations in the fourth quarter of 2014. During 2015, the Corporation’s transportation costs have increased to accommodate a greater proportion of blend sales now being directly sold to refineries at the refinery gate. The Corporation will have increased access to the U.S. Gulf Coast on the Flanagan-Seaway pipeline system in January 2016. Interest expense increased primarily as a result of the weakening of the Canadian dollar relative to the U.S. dollar, as the Corporation's debt is denominated in U.S. dollars and lower capitalized interest.

Cash Flow from (Used in) Operations – Year Ended December 31, 2015



(1) *Net of diluent.*
(2) *Defined as transportation expense less transportation revenue.*
(3) *Includes non-energy and energy operating costs, reduced by power revenue.*
(4) *Includes cash interest expense, net of capitalized interest, and realized gain/loss on interest rate swaps less interest income.*

Cash flow from operations was $49.5 million for the year ended December 31, 2015 compared to cash flow from operations of $791.5 million for the year ended December 31, 2014. Cash flow from operations decreased primarily due to lower bitumen realization, higher transportation and higher interest costs, partially offset by an increase in bitumen sales volumes and lower royalties.

Operating Earnings (Loss)

The Corporation recognized an operating loss of $140.2 million for the three months ended December 31, 2015 compared to operating earnings of $8.1 million for the three months ended December 31, 2014. The decrease was due to lower bitumen realization, primarily as a result of the significant decline of U.S. crude oil benchmark pricing, higher transportation costs, an increase in depletion and depreciation expense and an increase in interest expense, partially offset by an increase in bitumen sales volumes and lower royalties.

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

Revenue

Revenue for the three months ended December 31, 2015 totalled $444.5 million compared to $614.8 million for the three months ended December 31, 2014. Revenue for the year ended December 31, 2015 totalled $1.9 billion compared to $2.8 billion for the year ended December 31, 2014. Revenue decreased primarily due to a decrease in blend sales revenue as a result of the significant decline of U.S. crude oil benchmark pricing. Revenue represents the total of Petroleum revenue, net of royalties and Other revenue.

Net Loss

The Corporation recognized a net loss of $297.3 million for the three months ended December 31, 2015 compared to a net loss of $150.1 million for the three months ended December 31, 2014. The net loss for the three months ended December 31, 2015 included a net unrealized foreign exchange loss of $159.0 million on the Corporation's U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents and other expenses related to onerous contracts and contract cancellation expense totalling $77.5 million, partially offset by a gain of $68.2 million related to a sale of a non-core undeveloped oil sands asset. The net loss for the three months ended December 31, 2014 included a net unrealized foreign exchange loss of $139.0 million on U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents and other expenses related to contract cancellation expense and an inventory write-down totalling $36.1 million.

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

Total Cash Capital Investment

Total cash capital investment during the three months ended December 31, 2015 totalled $54.5 million compared to $324.0 million for the three months ended December 31, 2014. Total cash capital investment during the year ended December 31, 2015 totalled $257.2 million compared to $1.2 billion for the year ended December 31, 2014. Capital investment in 2015 was primarily directed towards sustaining and maintenance activities, as the Corporation has been focused on reducing capital spending until there is a sustained improvement in crude oil pricing.

Capital Resources

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

All of the Corporation’s long-term debt is denominated in U.S. dollars. As a result of the decrease in the value of the Canadian dollar relative to the U.S. dollar, long-term debt increased to C$5.2 billion as at December 31, 2015 from C$4.4 billion as at December 31, 2014. All of MEG’s long-term debt is “covenant lite” in structure, meaning it is free of any financial maintenance covenants and is not dependent on, nor calculated from, the Corporation’s crude oil reserves. The first maturity of any of the Corporation’s long-term debt obligations is March 2020.

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

OUTLOOK

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

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

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

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

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

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

(1) *Initial guidance was announced on December 4, 2015.*

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

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

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

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

BUSINESS ENVIRONMENT

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

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

Crude Oil Pricing

Brent crude is the primary world price benchmark for global light sweet crude oil. The Brent benchmark price averaged US$44.71 per barrel in the fourth quarter of 2015 compared to US$51.17 per barrel for the third quarter of 2015 and US$76.98 per barrel for the fourth quarter of 2014. The Brent benchmark price averaged US$53.62 per barrel for the year ended December 31, 2015 compared to US$99.66 per barrel for the year ended December 31, 2014. The global supply of crude oil is currently greater than demand, which has resulted in a decrease in prices.

The price of WTI is the current benchmark for mid-continent North American crude oil prices, at Cushing Oklahoma, and its Canadian dollar equivalent is the basis for determining royalties on the Corporation's bitumen sales. The WTI price averaged US$42.18 per barrel in the fourth quarter of 2015 compared to US$46.43 per barrel for the third quarter of 2015 and US$73.15 per barrel for the fourth quarter of 2014. The WTI price averaged US$48.80 per barrel for the year ended December 31, 2015 compared to US$93.00 per barrel for the year ended December 31, 2014. The global supply of crude oil is currently greater than demand, which has resulted in a decrease in prices.

The WCS benchmark reflects North American prices at Hardisty, Alberta. WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. WCS typically trades at a differential below the WTI benchmark price. The WTI:WCS differential averaged $19.35 per barrel or 34.4% for the fourth quarter of 2015, compared to $16.34 per barrel or 19.7% for the fourth quarter of 2014. The WTI:WCS differential averaged $17.29 per barrel or

27.7% for the year ended December 31, 2015, compared to $21.63 per barrel or 21.1% for the same period in 2014.

In order to facilitate pipeline transportation, MEG uses condensate as diluent for blending with the Corporation's bitumen. Condensate prices, benchmarked at Edmonton, averaged $55.57 per barrel in the fourth quarter of 2015 compared to $81.98 per barrel for the fourth quarter of 2014. The condensate price averaged $60.30 per barrel for the year ended December 31, 2015 compared to $102.92 per barrel for the year ended December 31, 2014.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, as it is used as fuel to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facilities. The AECO natural gas price averaged $2.57 per mcf for the fourth quarter of 2015 compared to $3.58 per mcf for the fourth quarter of 2014. The AECO natural gas price averaged $2.71 per mcf for the year ended December 31, 2015 compared to $4.50 per mcf for the year ended December 31, 2014. The North American natural gas supply is currently greater than demand, which has resulted in a decrease in prices. Natural gas prices have fallen to multi-year lows due to high inventory levels caused by unseasonably warm temperatures during the fourth quarter of 2015. Average prices have fallen 40% in 2015 from the 2014 average.

Power Prices

Electric power prices impact the price that the Corporation receives on the sale of surplus power from the Corporation's cogeneration facilities. The Alberta power pool price averaged $21.19 per megawatt hour for the fourth quarter of 2015 compared to $30.55 per megawatt hour for the fourth quarter of 2014. The Alberta power pool price decreased primarily due to the surplus of power generation capacity in the province and unseasonably warm temperatures experienced in November and December of 2015.

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

Foreign Exchange Rates

Changes in the value of the Canadian dollar relative to the U.S. dollar have an impact on the Corporation's blend sales revenue and cost of diluent, as blend sales prices and cost of diluent are determined by reference to U.S. benchmarks. Changes in the value of the Canadian dollar relative to the U.S. dollar also have an impact on principal and interest payments on the Corporation's U.S. dollar denominated debt. A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on blend sales revenue and a negative impact on the cost of diluent and principal and interest payments, while an increase in the value of the Canadian dollar has a negative impact on blend sales revenue and a positive impact on the cost of diluent and principal and interest payments. The Corporation recognizes net unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents at each reporting date. As at December 31, 2015, the Canadian dollar, at a rate of 1.3840, had decreased in value by approximately 3% against the U.S. dollar compared to its value as at September 30, 2015, when the rate was 1.3394. During the year ended December 31, 2015, the Canadian dollar weakened in value by approximately 19%.

RESULTS OF OPERATIONS

COMPARISON OF THE THREE MONTHS ENDED DECEMBER 31, 2015 TO DECEMBER 31, 2014

	Three months ended December 31	
	2015	**2014**
Bitumen production – bbls/d	**83,514**	80,349
Steam to oil ratio (SOR)	**2.5**	2.5

Bitumen Production

Production for the three months ended December 31, 2015 averaged 83,514 bbls/d compared to 80,349 bbls/d for the three months ended December 31, 2014. The increase in production volumes is primarily due to efficiency gains associated with RISER at the Christina Lake Project. The implementation of the RISER initiative has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production to sustain current production levels.

Steam to Oil Ratio

The Corporation continues to focus on increasing production and maintaining efficiency of current production through a lower SOR, which is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR averaged 2.5 during the three months ended December 31, 2015 and December 31, 2014.

Operating Cash Flow

	Three months ended December 31	
($000)	2015	2014
Petroleum revenue – proprietary(1)	$ 386,689	$ 592,518
Diluent	(211,293)	(266,869)
	175,396	325,649
Royalties	(1,888)	(19,180)
Transportation expense	(44,437)	(19,028)
Operating expenses	(69,974)	(74,653)
Power revenue	5,441	9,339
Transportation revenue	3,905	7,313
Operating cash flow(2)	$ 68,443	$ 229,440

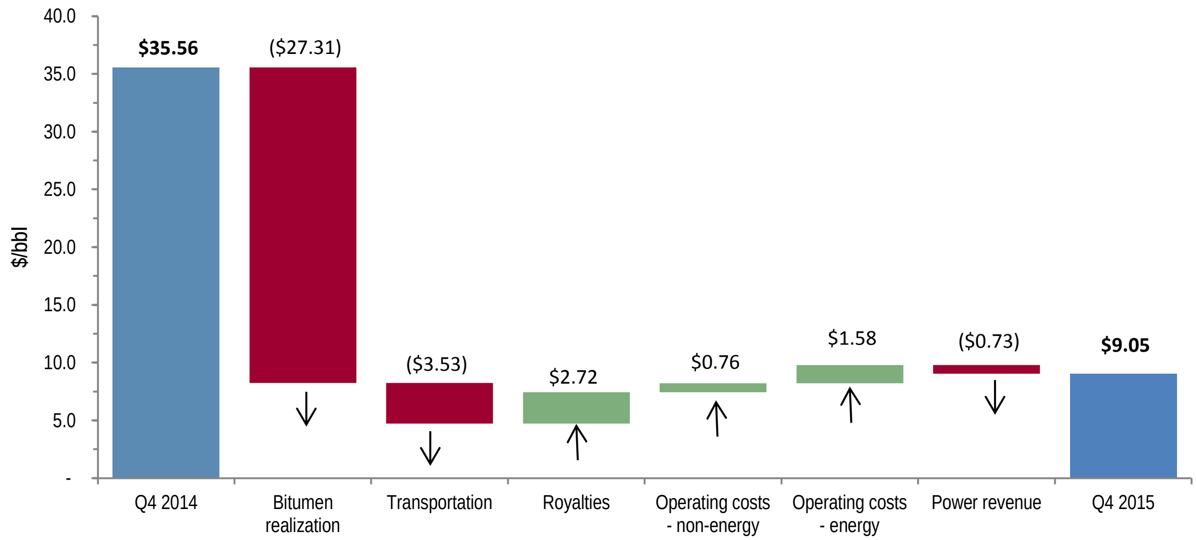
(1) Proprietary petroleum revenue represents MEG's revenue ("blend sales revenue") from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.

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

Blend sales revenue for the three months ended December 31, 2015 was $386.7 million compared to $592.5 million for the three months ended December 31, 2014. The decrease in blend sales revenue is due to a 45% decrease in the average realized blend price partially offset by an 18% increase in sales volumes. The cost of diluent for the three months ended December 31, 2015 was $211.3 million compared to $266.9 million for the three months ended December 31, 2014. The cost of diluent decreased primarily due to the decrease in condensate prices partially offset by higher volumes of diluent required for the increased blend sales volumes.

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

Cash Operating Netback



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

	Three months ended December 31	
($/bbl)	**2015**	**2014**
Bitumen realization[1]	**$ 23.17**	$ 50.48
Transportation[2]	**(5.35)**	(1.82)
Royalties	**(0.25)**	(2.97)
	17.57	45.69
Operating costs – non-energy	**(5.66)**	(6.42)
Operating costs – energy	**(3.58)**	(5.16)
Power revenue	**0.72**	1.45
Net operating costs	**(8.52)**	(10.13)
Cash operating netback	**$ 9.05**	$ 35.56

(1) Blend sales revenue 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 blend sales revenue, net of the cost of diluent. Bitumen realization averaged $23.17 per barrel for the three months ended December 31, 2015 compared to $50.48 per barrel for the three months ended December 31, 2014. The decrease in bitumen realization is primarily a result of the significant decline of U.S. crude oil benchmark pricing which resulted in lower blend sales revenue.

For the three months ended December 31, 2015, the Corporation's cost of diluent was $61.84 per barrel of diluent compared to $93.00 per barrel of diluent for the three months ended December 31, 2014. The decrease in the cost of diluent is primarily a result of the significant decline of U.S. crude oil benchmark pricing.

Transportation

Transportation costs 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 $5.35 per barrel for the three months ended December 31, 2015 compared to $1.82 per barrel for the three months ended December 31, 2014. Transportation expense increased primarily due to the cost of transporting blend volumes from Edmonton to the U.S. Gulf Coast via the Flanagan-Seaway Pipeline, which commenced operations in the fourth quarter of 2014. During 2015, the Corporation's transportation costs have increased to accommodate a greater proportion of blend sales now being directly sold to refineries at the refinery gate. These increasing direct sales to refineries at the refinery gate are a result of MEG's strategy of broadening market access to world prices to improve netbacks.

Royalties

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

Royalties averaged $0.25 per barrel during the three months ended December 31, 2015 compared to $2.97 per barrel for the three months ended December 31, 2014. The decrease in royalties is primarily attributable to the decrease in the Canadian dollar price of WTI and the decrease in bitumen realization.

On January 29, 2016, the Alberta government finalized results of a royalty review which commenced in September 2015. The modernized royalty framework retains the current structure and royalty rates for oil sands and increases the transparency of allowable costs.

Net Operating Costs

Non-energy operating costs

Non-energy operating costs decreased to $5.66 per barrel for the three months ended December 31, 2015 compared to $6.42 per barrel for the three months ended December 31, 2014. The decrease in non-energy operating costs is primarily the result of holding absolute costs relatively constant during a period of increasing sales volumes, as these costs are now spread over a greater number of barrels.

Energy operating costs

Energy operating costs averaged $3.58 per barrel for the three months ended December 31, 2015 compared to $5.16 per barrel for the three months ended December 31, 2014. The decrease in energy operating costs on a per barrel basis is primarily attributable to the decrease in natural gas prices. The Corporation's natural gas purchase price averaged $2.94 per mcf during the fourth quarter of 2015 compared to $3.50 per mcf for the fourth quarter of 2014.

Power revenue

Power revenue averaged $0.72 per barrel for the three months ended December 31, 2015 compared to $1.45 per barrel for the three months ended December 31, 2014. The decrease is primarily due to a decrease in the Corporation's realized power sales price. The Corporation's realized power price during the three months ended December 31, 2015 decreased to $19.67 per megawatt hour compared to $31.67 per megawatt hour for the same period in 2014. The decrease in the realized power sales price is primarily due to the current surplus of power generation capacity in the province of Alberta and unseasonably warm temperatures experienced in November and December of 2015.

COMPARISON OF THE YEAR ENDED DECEMBER 31, 2015 TO DECEMBER 31, 2014

	Year ended December 31	
	2015	**2014**
Bitumen production – bbls/d	**80,025**	71,186
Steam to oil ratio (SOR)	**2.5**	2.5

Bitumen Production

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

Steam to Oil Ratio

The Corporation continues to focus on increasing production and maintaining efficiency of current production through a lower SOR, which is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The SOR averaged 2.5 during the year ended December 31, 2015 and during the year ended December 31, 2014.

Operating Cash Flow

	Year ended December 31	
($000)	**2015**	**2014**
Petroleum revenue – proprietary[1]	**$ 1,799,154**	$ 2,701,801
Diluent	**(893,995)**	(1,163,637)
	905,159	1,538,164
Royalties	**(20,765)**	(107,074)
Transportation expense	**(156,382)**	(64,442)
Operating expenses	**(306,725)**	(351,534)
Power revenue	**29,239**	55,352
Transportation revenue	**13,824**	30,625
Operating cash flow[2]	**$ 464,350**	$ 1,101,091

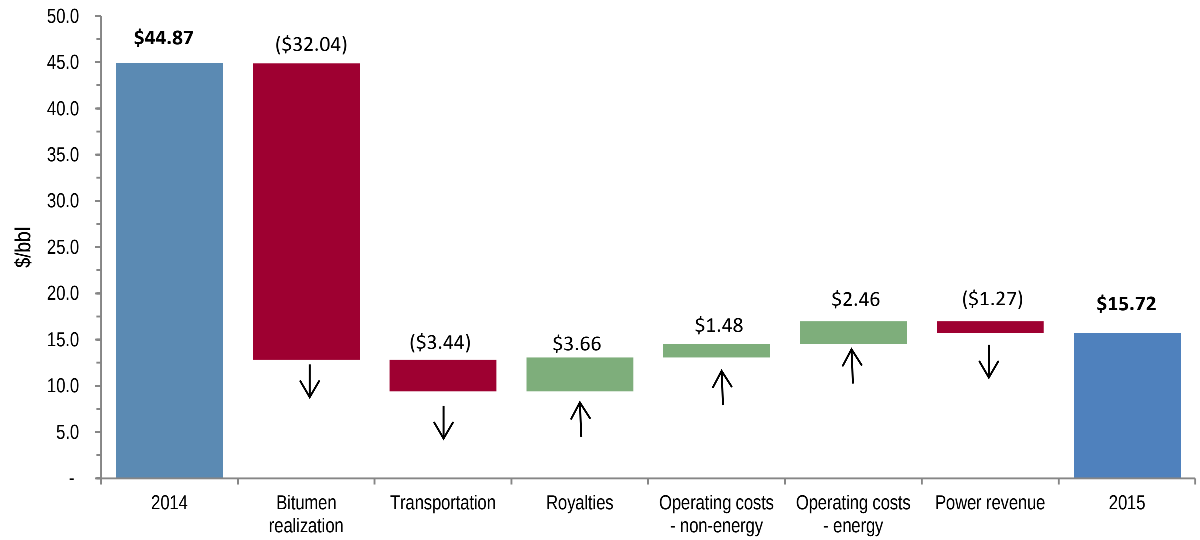
(1) Proprietary petroleum revenue represents MEG's revenue ("blend sales revenue") from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.

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

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

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

Cash Operating Netback



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

	Year ended December 31	
($/bbl)	**2015**	**2014**
Bitumen realization[1]	**$ 30.63**	$ 62.67
Transportation[2]	**(4.82)**	(1.38)
Royalties	**(0.70)**	(4.36)
	25.11	56.93
Operating costs – non-energy	**(6.54)**	(8.02)
Operating costs – energy	**(3.84)**	(6.30)
Power revenue	**0.99**	2.26
Net operating costs	**(9.39)**	(12.06)
Cash operating netback	**$ 15.72**	$ 44.87

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

Bitumen Realization

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

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

Transportation

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

Royalties

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

Net Operating Costs

Non-energy operating costs

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

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

Energy operating costs

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

Power revenue

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

OTHER OPERATING RESULTS

Net Marketing Activity

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Petroleum sales – third party	**$ 50,361**	$ 24,800	**$ 104,464**	$ 149,260
Purchased product and storage:				
Purchased product	**(50,339)**	(24,683)	**(101,928)**	(146,957)
Marketing and storage arrangements	**(7,580)**	(6,179)	**(27,687)**	(16,430)
	(57,919)	(30,862)	**(129,615)**	(163,387)
Net marketing activity(1)	**$ (7,558)**	$ (6,062)	**$ (25,151)**	$ (14,127)

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

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

Depletion and Depreciation

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Depletion and depreciation expense	**$ 127,153**	$ 100,722	**$ 467,422**	$ 378,544
Depletion and depreciation expense per barrel of production	**$ 16.55**	$ 13.63	**$ 16.00**	$ 14.57

Depletion and depreciation expense for the three months ended December 31, 2015 totalled $127.2 million compared to $100.7 million for the three months ended December 31, 2014. The increase is primarily due to an increase in bitumen production volumes, an increase in depreciable costs and an increase in estimated future development costs. Future development costs are a key element of the rate determination. The increase in the depletion and depreciation expense per barrel is primarily due to an increase in depreciable costs and an increase in the estimate of future development costs associated with the Corporation's proved reserves. Depletion and depreciation expense was $16.55 per barrel for the three months ended December 31, 2015 compared to $13.63 per barrel for the three months ended December 31, 2014.

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

General and Administrative

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
General and administrative expense	**$ 25,281**	$ 34,521	**$ 118,518**	$ 111,366
General and administrative expense per barrel of production	**$ 3.29**	$ 4.67	**$ 4.06**	$ 4.29

General and administrative expense for the three months ended December 31, 2015 was $25.3 million compared to $34.5 million for the three months ended December 31, 2014. General and administrative expense in the three months ended December 31, 2015 was lower primarily as a result of lower 2015 short-term incentive compensation recognized during the three months ended December 31, 2015 than was recognized in the fourth quarter of 2014. On a per barrel basis, general and administrative expense was $3.29 per barrel for the three months ended December 31, 2015 compared to $4.67 per barrel for the three months ended December 31, 2014.

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

Stock-based Compensation

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Stock-based compensation expense	**$ 12,039**	$ 12,746	**$ 50,105**	$ 48,310

The fair value of compensation associated with the granting of stock options, restricted share units ("RSUs") and performance share units ("PSUs") to directors, officers, employees and consultants is recognized by the Corporation as stock-based compensation expense. Fair value is determined using the Black-Scholes option pricing model. Stock-based compensation expense for the three months ended December 31, 2015 was $12.0 million compared to $12.7 million for the three months ended December

31, 2014. Stock-based compensation expense for the year ended December 31, 2015 was $50.1 million compared to $48.3 million for the year ended December 31, 2014.

Research and Development

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Research and development expense	**$ 2,467**	$ 2,197	**$ 7,497**	$ 6,003

Research and development expenditures related to the Corporation's research of crude quality improvement and related technologies have been expensed. Research and development expenditures were $2.5 million for the three months ended December 31, 2015 compared to $2.2 million for the three months ended December 31, 2014. Research and development expenditures were $7.5 million for the year ended December 31, 2015 compared to $6.0 million for the year ended December 31, 2014.

Gain on Disposition of Assets

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Gain on disposition of assets	**$ 68,192**	$ -	**$ 68,192**	$ -

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

Foreign Exchange Gain (Loss), Net

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ (169,572)**	$ (149,919)	**$ (852,422)**	$ (368,450)
US$ denominated cash, cash equivalents and other	**10,563**	10,910	**67,112**	35,301
Unrealized net loss on foreign exchange	**(159,009)**	(139,009)	**(785,310)**	(333,149)
Realized loss on foreign exchange	**(3,348)**	(1,781)	**(16,429)**	(5,480)
Foreign exchange loss, net	**$ (162,357)**	$ (140,790)	**$ (801,739)**	$ (338,629)

C$ equivalent of 1 US$				
Beginning of period	**1.3394**	1.1208	**1.1601**	1.0636
End of period	**1.3840**	1.1601	**1.3840**	1.1601

The Corporation recognized a net foreign exchange loss of $162.4 million for the three months ended December 31, 2015 compared to a net foreign exchange loss of $140.8 million for the three months ended December 31, 2014. The increase in the net foreign exchange loss is primarily due to an unrealized foreign exchange loss on the translation of the U.S. dollar denominated debt as a result of weakening of the Canadian dollar compared to the U.S. dollar.

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

Net Finance Expense

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Total interest expense	**$ 81,888**	$ 69,000	**$ 313,411**	$ 265,140
Less capitalized interest	**(5,970)**	(14,901)	**(56,449)**	(75,975)
Net interest expense	**75,918**	54,099	**256,962**	189,165
Accretion on decommissioning provision	**1,616**	1,270	**5,663**	4,535
Unrealized loss (gain) on derivative financial liabilities	**(15,890)**	5,444	**(13,289)**	(1,469)
Realized loss on interest rate swaps	**1,541**	1,311	**5,858**	5,056
Unrealized fair value gain on other assets	**-**	-	**-**	(429)
Net finance expense	**$ 63,185**	$ 62,124	**$ 255,194**	$ 196,858

Average effective interest rate(1)	**5.8%**	5.8%	**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 December 31, 2015 was $81.9 million compared to $69.0 million for the three months ended December 31, 2014. Total interest expense, before capitalization, for the year ended December 31, 2015 was $313.4 million compared to $265.1 million for the year ended December 31, 2014. Total interest expense for the three months and year ended December 31, 2015 increased due to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense.

The Corporation recognized an unrealized gain on derivative financial liabilities of $15.9 million for the three months ended December 31, 2015 compared to an unrealized loss of $5.4 million for the three months ended December 31, 2014. The Corporation recognized an unrealized gain on derivative financial liabilities of $13.3 million for the year ended December 31, 2015 compared to an unrealized gain of $1.5 million for the year ended December 31, 2014. These losses and gains relate to the change in fair value of the interest rate floor associated with the Corporation's senior secured term loan and the change in fair value of the Corporation’s interest rate swap contracts.

The Corporation realized a loss on the interest swap contracts of $1.5 million and $5.9 million for the three and twelve months ended December 31, 2015, respectively, compared to a realized loss of $1.3 million and $5.1 million for the three and twelve months ended December 31, 2014, respectively.

Other Expenses

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Onerous contracts	**$ 58,719**	$ -	**$ 58,719**	$ -
Contract cancellation expense	**18,759**	16,455	**12,879**	16,455
Inventory write-down	**-**	19,668	**-**	19,668
Other expenses	**$ 77,478**	$ 36,123	**$ 71,598**	$ 36,123

The Corporation recognized other expenses of $77.5 million for the three months and $71.6 million for the year ended December 31, 2015 compared to $36.1 million for the three months and the year ended December 31, 2014.

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

For the three months ended December 31, 2015, the Corporation recognized contract cancellation expense of $18.8 million primarily relating to the termination of a marketing transportation contract. For the year ended December 31, 2015, the Corporation recognized contract cancellation expense of $12.9 million which includes the termination of the marketing transportation contract, partially offset by a recovery recorded in the second quarter of 2015. For both the three months and year ended December 31, 2014, the Corporation recognized $16.5 million of field asset construction cancellation expense relating to the reduction of the Corporation's capital program.

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

Income Tax Expense (Recovery)

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Current income tax (recovery)	**$ -**	$ -	**$ (1,200)**	$ -
Deferred income tax expense (recovery)	**(42,935)**	(14,007)	**(90,733)**	85,776
Income tax expense (recovery)	**$ (42,935)**	$ (14,007)	**$ (91,933)**	$ 85,776

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

The Corporation recognized a deferred income tax recovery of $42.9 million for the three months ended December 31, 2015 compared to a deferred income tax recovery of $14.0 million for the three months ended December 31, 2014. The Corporation recognized a deferred income tax recovery of $90.7 million for the year ended December 31, 2015 compared to deferred income tax expense of $85.8 million for the year ended December 31, 2014.

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

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

- The permanent difference due to the non-taxable portion of unrealized foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the three months ended December 31, 2015, the non-taxable loss was $84.8 million compared to a non-taxable loss of $75.0 million for the three months ended December 31, 2014. For the year ended December 31, 2015, the non-taxable loss was $426.2 million compared to a non-taxable loss of $184.2 million for the year ended December 31, 2014.

- Stock-based compensation expense is a permanent difference. Stock-based compensation expense was $12.0 million for the three months ended December 31, 2015 compared to $12.7 million for the three months ended December 31, 2014. Stock-based compensation expense for the year ended December 31, 2015 was $50.1 million compared to $48.3 million for the year ended December 31, 2014.

- During the year ended December 31, 2015, a deferred tax recovery of $5.5 million was recognized relating to a tax deduction available for the fair market value of vested RSUs.

As of December 31, 2015, the Corporation is not currently taxable and had approximately $7.3 billion of available tax pools and had recognized a deferred income tax liability of $87.5 million. In addition, at December 31, 2015, the Corporation had $626.4 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects. As at December 31, 2015, the Corporation had not recognized the tax benefit related to $698.0 million of unrealized taxable capital foreign exchange losses ($273.7 million as at December 31, 2014).

NET CAPITAL INVESTING

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Total cash capital investment	**$ 54,473**	$ 323,970	**$ 257,178**	$ 1,237,539
Capitalized interest	**5,970**	14,901	**56,449**	75,975
	60,443	338,871	**313,627**	1,313,514
Dispositions	**(41,827)**	-	**(41,827)**	-
Net capital investment	**$ 18,616**	$ 338,871	**$ 271,800**	$ 1,313,514

Total cash capital investment for the three months ended December 31, 2015 was $54.5 million in comparison to $324.0 million for the three months ended December 31, 2014. Total cash capital investment for the year ended December 31, 2015 was $257.2 million in comparison to $1.2 billion for the year ended December 31, 2014. Total cash capital investing for 2015 was primarily directed to sustaining and maintenance capital activities as the Corporation has been focused on reducing capital spending until there is a sustained improvement in crude oil pricing. During the fourth quarter of 2015, the Corporation divested of a non-core undeveloped oil sands asset for proceeds of $110.0 million.

During the year ended December 31, 2015, turnaround costs of $22.9 million have been capitalized as there is future economic benefit associated with the work performed. As a result, the cost of the 2015 turnaround is treated as a component of capital investment and depreciated on a straight line basis over the period to the next turnaround.

The Corporation capitalizes interest associated with qualifying assets. A total of $6.0 million of interest was capitalized during the three months ended December 31, 2015 in comparison to $14.9 million for the three months ended December 31, 2014. A total of $56.4 million of interest was capitalized during the year ended December 31, 2015 in comparison to $76.0 million for the year ended December 31, 2014.

NON-GAAP MEASURES

Certain financial measures in this document 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 11 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, contract cancellation expense, payments on onerous contracts and decommissioning expenditures while the IFRS measurement "Net cash provided by (used in) operating activities" includes these items. Cash flow from (used in) operations is reconciled to Net cash provided by (used in) operating activities in the table below.

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Net cash provided by operating activities	**$ 12,515**	$ 209,985	**$ 112,158**	$ 767,500
Add (deduct):				
Net change in non-cash operating working capital items	**(76,388)**	(93,313)	**(77,991)**	5,610
Contract cancellation expense	**18,759**	16,455	**12,879**	16,455
Payments on onerous contracts	**541**	-	**541**	-
Decommissioning expenditures	**443**	972	**1,873**	1,893
Cash flow from (used in) operations	**$ (44,130)**	$ 134,099	**$ 49,460**	$ 791,458

Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP measure which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating earnings (loss) is defined as net earnings (loss) as reported, excluding gains (losses) on disposition of assets, unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial liabilities, unrealized fair value gains and losses on other assets, onerous contracts, contract cancellation expense and the respective deferred tax impact of these adjustments. Operating earnings (loss) is reconciled to "Net loss", the nearest IFRS measure, in the table below.

	Three months ended December 31		Year ended December 31	
($000)	**2015**	**2014**	**2015**	**2014**
Net loss	**$ (297,275)**	$ (150,076)	**$ (1,169,671)**	$ (105,538)
Add (deduct):				
Gain on disposition of assets [1]	**(68,192)**	-	**(68,192)**	-
Unrealized net loss on foreign exchange[2]	**159,009**	139,009	**785,310**	333,149
Unrealized loss (gain) on derivative financial liabilities[3]	**(15,890)**	5,444	**(13,289)**	(1,469)
Unrealized fair value gain on other assets	**-**	-	**-**	(429)
Onerous contracts [4]	**58,719**	-	**58,719**	-
Contract cancellation expense [5]	**18,759**	16,455	**12,879**	16,455
Deferred tax expense relating to these adjustments	**4,636**	(2,748)	**19,870**	5,185
Operating earnings (loss)	**$ (140,234)**	$ 8,084	**$ (374,374)**	$ 247,353

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

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

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

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

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

Operating Cash Flow

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

ABBREVIATIONS

The following provides a summary of common abbreviations used in this document:

Financial and Business Environment

AECO	Alberta natural gas price reference location
AIF	Annual Information Form
AWB	Access Western Blend
$ or C$	Canadian dollars
C5+	Condensate
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam to oil ratio
U.S.	United States
US$	United States dollars
WCS	Western Canadian Select
WTI	West Texas Intermediate

Measurement

bbl	barrel
bbls/d	barrels per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
MW	megawatts
MW/h	megawatts per hour

ADVISORY

Forward-Looking Information

This document may contain forward-looking information including but not limited to: expectations of future production, revenues, expenses, cash flow, operating costs, steam-oil ratios, pricing differentials, reliability, profitability and capital investments; estimates of reserves and resources; the anticipated reductions in operating costs as a result of optimization and scalability of certain operations; and the anticipated sources of funding for operations and capital investments. Such forward-looking information is based on management's expectations and assumptions regarding future growth, results of operations, production, future capital and other expenditures, plans for and results of drilling activity, environmental matters, business prospects and opportunities.

By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: risks associated with the oil and gas industry, for example, the securing of adequate supplies and access to markets and transportation infrastructure; the availability of capacity on the electricity transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and revenues; health, safety and environmental risks; risks of legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws; assumptions regarding and the volatility of commodity prices 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 the capacities and performance associated with MEG's projects.

Although MEG believes that the assumptions used in such forward-looking information are reasonable, there can be no assurance that such assumptions will be correct. Accordingly, readers are cautioned that the actual results achieved may vary from the forward-looking information provided herein and that the variations may be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive.

Further information regarding the assumptions and risks inherent in the making of forward-looking statements can be found in MEG's most recently filed annual information form ("AIF"), along with MEG's other public disclosure documents. Copies of the AIF and MEG's other public disclosure documents are available through the SEDAR website which is available at www.sedar.com.

The forward-looking information included in this document is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this document is made as of the date of this document and the Corporation assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

Non-GAAP Financial Measures

Certain financial measures in this document 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 document.

ADDITIONAL INFORMATION

Additional information relating to the Corporation, including its AIF, is available on MEG's website at www.megenergy.com and is also available on SEDAR at www.sedar.com.

QUARTERLY SUMMARIES

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

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

Interim Consolidated Financial Statements

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

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

Commitments and contingencies (note 22)

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 December 31		Year ended December 31	
	Note	**2015**	**2014**	**2015**	**2014**
Petroleum revenue, net of royalties	11	**$ 435,162**	$ 598,138	**$ 1,882,853**	$ 2,743,987
Other revenue	12	**9,346**	16,652	**43,063**	85,977
		444,508	614,790	**1,925,916**	2,829,964
Diluent and transportation	13	**255,730**	285,897	**1,050,377**	1,228,079
Operating expenses		**69,974**	74,653	**306,725**	351,534
Purchased product and storage		**57,920**	30,862	**129,615**	163,387
Depletion and depreciation	4,6	**127,153**	100,722	**467,422**	378,544
General and administrative		**25,281**	34,521	**118,518**	111,366
Stock-based compensation	10	**12,039**	12,746	**50,105**	48,310
Research and development		**2,467**	2,197	**7,497**	6,003
		550,564	541,598	**2,130,259**	2,287,223
Revenues less expenses		**(106,056)**	73,192	**(204,343)**	542,741
Other income (expense)					
Gain on disposition of assets	5	**68,192**	-	**68,192**	-
Interest and other income		**674**	1,762	**3,078**	9,107
Foreign exchange loss, net	14	**(162,357)**	(140,790)	**(801,739)**	(338,629)
Net finance expense	15	**(63,185)**	(62,124)	**(255,194)**	(196,858)
Other expenses	16	**(77,478)**	(36,123)	**(71,598)**	(36,123)
		(234,154)	(237,275)	**(1,057,261)**	(562,503)
Loss before income taxes		**(340,210)**	(164,083)	**(1,261,604)**	(19,762)
Income tax expense (recovery)	17	**(42,935)**	(14,007)	**(91,933)**	85,776
Net loss		**(297,275)**	(150,076)	**(1,169,671)**	(105,538)
Other comprehensive income, net of tax					
Items that may be reclassified to profit or loss:					
Foreign currency translation adjustment		**4,814**	5,600	**22,358**	10,332
Comprehensive loss for the period		**$ (292,461)**	$ (144,476)	**$(1,147,313)**	$ (95,206)
Net loss per common share					
Basic	19	**$ (1.32)**	$ (0.67)	**$ (5.21)**	$ (0.47)
Diluted	19	**$ (1.32)**	$ (0.67)	**$ (5.21)**	$ (0.47)

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

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

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

		Three months ended December 31		Year ended December 31	
	Note	**2015**	**2014**	**2015**	**2014**
Cash provided by (used in):					
Operating activities					
Net loss		**$ (297,275)**	$ (150,076)	**$ (1,169,671)**	$ (105,538)
Adjustments for:					
Depletion and depreciation	4,6	**127,153**	100,722	**467,422**	378,544
Stock-based compensation	10	**12,039**	12,746	**50,105**	48,310
Gain on disposition of assets	5	**(68,192)**	-	**(68,192)**	-
Unrealized loss on foreign exchange	14	**159,009**	139,009	**785,310**	333,149
Unrealized (gain) loss on derivative financial liabilities	15	**(15,890)**	5,444	**(13,289)**	(1,469)
Onerous contracts	16	**58,719**	-	**58,719**	-
Inventory write-down	16	**-**	19,668	**-**	19,668
Deferred income tax expense (recovery)	17	**(42,935)**	(14,007)	**(90,733)**	85,776
Amortization of debt issue costs	7,8	**2,998**	2,936	**11,795**	10,566
Other		**1,485**	1,202	**5,115**	5,997
Decommissioning expenditures	9	**(443)**	(972)	**(1,873)**	(1,893)
Payments on onerous contracts	9	**(541)**	-	**(541)**	-
Net change in non-cash working capital items	18	**76,388**	93,313	**77,991**	(5,610)
Net cash provided by (used in) operating activities		**12,515**	209,985	**112,158**	767,500
Investing activities					
Capital investments					
Property, plant and equipment	4	**(58,976)**	(325,259)	**(305,670)**	(1,282,194)
Exploration and evaluation	5	**(136)**	(1,199)	**(1,458)**	(7,749)
Other intangible assets	6	**(1,331)**	(12,413)	**(6,498)**	(23,571)
Proceeds on disposition of assets	5	**110,015**	-	**110,015**	-
Other		**(339)**	2,318	**(930)**	4,420
Net change in non-cash working capital items	18	**(10,830)**	8,601	**(212,455)**	(3,346)
Net cash provided by (used in) investing activities		**38,403**	(327,952)	**(416,996)**	(1,312,440)
Financing activities					
Repayment of long-term debt	8	**(4,512)**	(3,769)	**(17,020)**	(14,467)
Issue of shares	10	**-**	436	**-**	11,166
Financing costs		**-**	(10,035)	**-**	(10,035)
Net cash provided by (used in) financing activities		**(4,512)**	(13,368)	**(17,020)**	(13,336)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**11,071**	10,910	**73,974**	35,301
Change in cash and cash equivalents		**57,477**	(120,425)	**(247,884)**	(522,975)
Cash and cash equivalents, beginning of period		**350,736**	776,522	**656,097**	1,179,072
Cash and cash equivalents, end of period		**$ 408,213**	$ 656,097	**$ 408,213**	$ 656,097

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 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 on February 3, 2016.

3. CHANGE IN ACCOUNTING POLICIES

New accounting standards

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

Accounting standards issued but not yet applied

On July 22, 2015, the IASB issued an amendment to IFRS 15, Revenue from Contracts with Customers ("IFRS 15"), deferring the effective date by one year to annual periods beginning on or after January 1, 2018. IFRS 15 provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework. The Corporation is currently assessing the impact of the adoption of IFRS 15 on the Corporation's consolidated financial statements.

On January 13, 2016, the IASB issued IFRS 16, Leases ("IFRS 16") which will replace IAS 17, Leases. Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. The new standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted. The Corporation is currently assessing the impact of the adoption of IFRS 16 on the Corporation's consolidated financial statements.

A description of additional accounting standards that are anticipated to be adopted by the Corporation in future periods is provided within Note 3 of the Corporation's audited consolidated financial statements for the year ended December 31, 2014.

4. PROPERTY, PLANT AND EQUIPMENT

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

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

5. EXPLORATION AND EVALUATION ASSETS

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

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. These assets are not subject to depletion, as they are in the exploration and evaluation stage, but are reviewed on a quarterly basis for any indication of impairment. As at December 31, 2015, these assets were assessed for impairment within the aggregation of all of the Corporation's CGUs and no impairment was recognized. During the year ended December 31, 2015, the Corporation did not capitalize any interest and finance charges related to exploration and evaluation assets (year ended December 31, 2014 - $1.3 million).

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

6. OTHER INTANGIBLE ASSETS

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

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

Carrying amounts		
Balance as at December 31, 2014	$	83,090
Balance as at December 31, 2015	**$**	**84,142**

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

7. OTHER ASSETS

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

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

8. LONG-TERM DEBT

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

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

All of the Corporation's long-term debt is "covenant lite" in structure, meaning it is free of any financial maintenance covenants and is not dependent on, nor calculated from, the Corporation's crude oil reserves. The first maturity of any of the Corporation's long-term debt obligations is March 2020.

9. PROVISIONS AND OTHER LIABILITIES

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

(a) Decommissioning provision:

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

As at December 31		**2015**		**2014**
Balance, beginning of year	**$**	**156,382**	$	108,695
Changes in estimated future cash flows		**14,076**		20,406
Changes in discount rates		**(48,933)**		13,798
Liabilities incurred		**5,066**		10,841
Liabilities settled		**(1,873)**		(1,893)
Accretion		**5,663**		4,535
Balance, end of year		**130,381**		156,382
Less current portion		**(1,485)**		(1,835)
Non-current portion	**$**	**128,896**	$	154,547

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The Corporation has estimated the net present value of the decommissioning obligations using a credit-adjusted risk-free rate of 8.3% (December 31, 2014 – 6.0%).

(b) Onerous contracts:

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

(c) Derivative financial liabilities:

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

10. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

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

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

(c) Stock options outstanding:

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

Year ended December 31, 2015	**Stock options**	**Weighted average exercise price**
Outstanding, beginning of year	**7,865,788**	**$ 34.87**
Granted	**2,968,798**	**18.55**
Forfeited	**(531,473)**	**31.49**
Expired	**(377,800)**	**41.00**
Outstanding, end of year	**9,925,313**	**$ 29.94**

(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.

Year ended December 31, 2015	
Outstanding, beginning of year	**2,745,439**
Granted	**1,996,841**
Vested and released	**(1,150,098)**
Forfeited	**(312,070)**
Outstanding, end of year	**3,280,112**

(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 December 31, 2015, there were 47,696 DSUs outstanding (December 31, 2014 – 17,281 DSUs outstanding).

(f) Contributed surplus:

Year ended December 31, 2015		
Balance, beginning of year	**$**	**153,837**
Stock-based compensation - expensed		**50,105**
Stock-based compensation - capitalized		**6,840**
RSUs vested and released		**(38,947)**
Balance, end of year	**$**	**171,835**

11. PETROLEUM REVENUE, NET OF ROYALTIES

	Three months ended December 31				**Year ended December 31**			
		2015		**2014**		**2015**		**2014**
Petroleum revenue:								
Proprietary	**$**	**386,689**	$	592,518	**$**	**1,799,154**	$	2,701,801
Third party [(a)]		**50,361**		24,800		**104,464**		149,260
		437,050		617,318		**1,903,618**		2,851,061
Royalties		**(1,888)**		(19,180)		**(20,765)**		(107,074)
Petroleum revenue, net of royalties	**$**	**435,162**	$	598,138	**$**	**1,882,853**	$	2,743,987

(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".

12. OTHER REVENUE

	Three months ended December 31				**Year ended December 31**			
		2015		**2014**		**2015**		**2014**
Power revenue	**$**	**5,441**	$	9,339	**$**	**29,239**	$	55,352
Transportation revenue		**3,905**		7,313		**13,824**		30,625
Other revenue	**$**	**9,346**	$	16,652	**$**	**43,063**	$	85,977

13. DILUENT AND TRANSPORTATION

	Three months ended December 31		Year ended December 31	
	2015	2014	**2015**	2014
Diluent	**$ 211,293**	$ 266,869	**$ 893,995**	$ 1,163,637
Transportation	**44,437**	19,028	**156,382**	64,442
Diluent and transportation	**$ 255,730**	$ 285,897	**$ 1,050,377**	$ 1,228,079

14. FOREIGN EXCHANGE LOSS, NET

	Three months ended December 31		Year ended December 31	
	2015	2014	**2015**	2014
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ (169,572)**	$ (149,919)	**$ (852,422)**	$ (368,450)
US$ denominated cash, cash equivalents and other	**10,563**	10,910	**67,112**	35,301
Unrealized net loss on foreign exchange	**(159,009)**	(139,009)	**(785,310)**	(333,149)
Realized loss on foreign exchange	**(3,348)**	(1,781)	**(16,429)**	(5,480)
Foreign exchange loss, net	**$ (162,357)**	$ (140,790)	**$ (801,739)**	$ (338,629)

15. NET FINANCE EXPENSE

	Three months ended December 31		Year ended December 31	
	2015	2014	**2015**	2014
Total interest expense	**$ 81,888**	$ 69,000	**$ 313,411**	$ 265,140
Less capitalized interest	**(5,970)**	(14,901)	**(56,449)**	(75,975)
Net interest expense	**75,918**	54,099	**256,962**	189,165
Accretion on decommissioning provision	**1,616**	1,270	**5,663**	4,535
Unrealized (gain) loss on derivative financial liabilities	**(15,890)**	5,444	**(13,289)**	(1,469)
Realized loss on interest rate swaps	**1,541**	1,311	**5,858**	5,056
Unrealized fair value gain on other assets	**-**	-	**-**	(429)
Net finance expense	**$ 63,185**	$ 62,124	**$ 255,194**	$ 196,858

16. OTHER EXPENSES

	Three months ended December 31		Year ended December 31	
	2015	**2014**	**2015**	**2014**
Onerous contracts[a]	**$ 58,719**	$ -	**$ 58,719**	$ -
Contract cancellation expense[b]	**18,759**	16,455	**12,879**	16,455
Inventory write-down[c]	**-**	19,668	**-**	19,668
Other expenses	**$ 77,478**	$ 36,123	**$ 71,598**	$ 36,123

(a) During the three months and year ended December 31, 2015 the Corporation recognized an expense of $58.7 million related to certain onerous Calgary office lease contracts (Note 9) (December 31, 2014 - nil).

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

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

17. INCOME TAX EXPENSE (RECOVERY)

	Three months ended December 31		Year ended December 31	
	2015	**2014**	**2015**	**2014**
Current income tax expense (recovery)	**$ -**	$ -	**$ (1,200)**	$ -
Deferred income tax expense (recovery)	**(42,935)**	(14,007)	**(90,733)**	85,776
Income tax expense (recovery)	**$ (42,935)**	$ (14,007)	**$ (91,933)**	$ 85,776

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

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

18. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended December 31		Year ended December 31	
	2015	2014	**2015**	2014
Cash provided by (used in):[a]				
Trade receivables and other	**$ 20,593**	$ 80,105	**$ 46,852**	$ 9,941
Inventories	**17,669**	(26,649)	**47,492**	(30,519)
Accounts payable and accrued liabilities	**27,296**	48,458	**(228,808)**	11,622
	$ 65,558	$ 101,914	**$ (134,464)**	$ (8,956)
Changes in non-cash working capital relating to:				
Operating	**$ 76,388**	$ 93,313	**$ 77,991**	$ (5,610)
Investing	**(10,830)**	8,601	**(212,455)**	(3,346)
	$ 65,558	$ 101,914	**$ (134,464)**	$ (8,956)
Cash and cash equivalents:[b]				
Cash	**$ 222,341**	$ 273,846	**$ 222,341**	$ 273,846
Cash equivalents	**185,872**	382,251	**185,872**	382,251
	$ 408,213	$ 656,097	**$ 408,213**	$ 656,097

(a) The amounts for the three months and year ended December 31, 2015, exclude non-cash working capital items primarily related to the $52.2 million transferred from inventory to other assets (Note 7).

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

19. NET LOSS PER COMMON SHARE

	Three months ended December 31		Year ended December 31	
	2015	**2014**	**2015**	**2014**
Net loss	**$ (297,275)**	$ (150,076)	**$ (1,169,671)**	$ (105,538)
Weighted average common shares outstanding	**225,102,632**	223,866,119	**224,579,249**	223,314,791
Dilutive effect of stock options, RSUs and PSUs[(a)]	**-**	-	**-**	-
Weighted average common shares outstanding – diluted	**225,102,632**	223,866,119	**224,579,249**	223,314,791
Net loss per share, basic	**$ (1.32)**	$ (0.67)	**$ (5.21)**	$ (0.47)
Net loss per share, diluted	**$ (1.32)**	$ (0.67)	**$ (5.21)**	$ (0.47)

(a) For the three months and year ended December 31, 2015, 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 and year ended December 31, 2015, the dilutive effect of stock options, RSUs and PSUs would have been 321,530 (three months ended December 31, 2014 – 801,663) and 564,201 (year ended December 31, 2014 – 1,371,687) weighted average common shares, respectively.

20. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments recognized on the Consolidated Balance Sheet are comprised of cash and cash equivalents, trade receivables and other, U.S. auction rate securities ("ARS") included within other assets, accounts payable and accrued liabilities, derivative financial liabilities and long-term debt. As at December 31, 2015, the ARS and derivative financial liabilities were classified as held-for-trading financial instruments; cash and cash equivalents and trade receivables and other were classified as loans and receivables; and accounts payable and accrued liabilities were classified as other financial liabilities. Long-term debt was carried at amortized cost.

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

(a) Fair value measurement of ARS, long-term debt and derivative financial liabilities:

		Fair value measurements using		
As at December 31, 2015	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
ARS (Note 7)	**$ 3,470**	**$ -**	**$ 3,470**	**$ -**
Financial liabilities				
Long-term debt[1] (Note 8)	**5,257,124**	**-**	**3,999,317**	**-**
Derivative financial liabilities (Note 9)	**16,223**	**-**	**16,223**	**-**

		Fair value measurements using		
As at December 31, 2014	**Carrying amount**	**Level 1**	**Level 2**	**Level 3**
Recurring measurements:				
Financial assets				
ARS (Note 7)	$ 2,908	$ -	$ 2,908	$ -
Financial liabilities				
Long-term debt[1] (Note 8)	4,421,721	4,075,233	-	-
Derivative financial liabilities (Note 9)	29,511	-	29,511	-

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

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

As at December 31, 2015, the Corporation did not have any financial instruments measured at Level 1 fair value.

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

The estimated fair values of the ARS and long-term debt are derived using quoted prices in an inactive market from a third-party independent broker.

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

Level 3 fair value measurements are based on unobservable information.

As at December 31, 2015, the Corporation did not have any financial instruments measured at Level 3 fair value.

The Corporation recognizes transfers into and transfers out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer. In 2015, the Corporation's long-term debt was transferred from Level 1 to Level 2 of the fair value hierarchy as its fair value was derived from observable inputs from a third-party independent broker.

(b) Interest rate risk management:

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. As noted below, in order to mitigate a portion of this risk, the Corporation has entered into interest rate swap contracts to effectively fix the interest rate on US$748.0 million of the US$1.249 billion senior secured term loan. Interest rate swaps are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

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

(1) London Interbank Offered Rate

21. GEOGRAPHICAL DISCLOSURE

As at December 31, 2015, the Corporation had non-current assets related to operations in the United States of $111.1 million (December 31, 2014 - $56.9 million). For the three months and year ended December 31, 2015, petroleum revenue related to operations in the United States was $121.2 million and $541.5 million, respectively (three months and year ended December 31, 2014 - $42.4 million and $131.4 million, respectively).

22. COMMITMENTS AND CONTINGENCIES

(a) Commitments

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

Operating:

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

Capital:

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

(b) Contingencies

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