FIRST QUARTER 2013

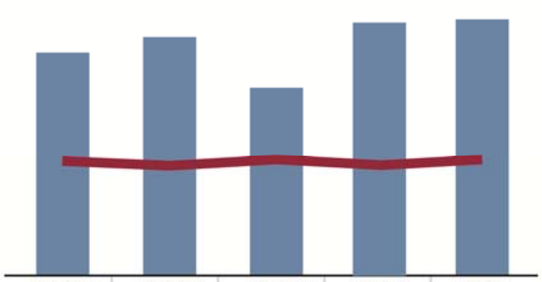
Report to Shareholders for the period ended March 31, 2013

MEG Energy Corp. ("MEG" or the "Corporation") reported first quarter 2013 operational and financial results on April 24, 2013. Highlights included:

- Record quarterly production volumes of 32,531 barrels per day as MEG drives toward a 2013 exit production rate 30% to 50% higher than 2012 average volumes and a nearly 180% increase over 2012 averages by early 2015;
- Low net operating costs of $10.44 per barrel, which mitigated the challenging price environment through January and February – prices began to improve in March and continued to strengthen in April;
- New eMSAGP wells demonstrating initial results consistent with the industry-leading steam-oil ratio performance of MEG's pilot wells using the technology;
- Ongoing progress on the Christina Lake Phase 2B project, which remains on schedule for initial steaming in the third quarter and full plant operations targeted to ramp up in the fourth quarter; and
- Receipt in the first quarter of dedicated barges to move crude oil around mid-continent pipeline congestion to reach higher-priced markets – initial deliveries by barge commenced in April.

"Although we faced challenging market conditions in the first two months of the quarter, MEG's operational results were outstanding, with record quarterly production," said Bill McCaffrey, MEG President and Chief Executive Officer. "The stage is set for what we see as a truly transformational year as we continue our efforts to drive higher production volumes through the RISER initiative and our target to more than double production capacity with the start-up of Phase 2B later in the year."

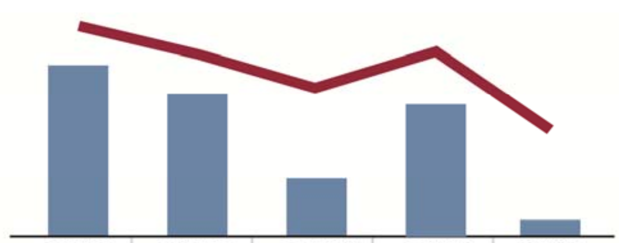
Operational Performance



	Q1/12	Q2/12	Q3/12*	Q4/12	Q1/13
Production (bpd)	28,446	30,429	23,941	32,292	32,531
SOR	2.5	2.4	2.5	2.4	2.5

*Planned plant turnaround

Financial Performance



	Q1/12	Q2/12	Q3/12*	Q4/12	Q1/13
Cash flow from operations ($mm)	72.0	60.0	24.4	56.1	7.1
Cash operating netback ($/bbl)	39.20	34.17	27.85	34.44	17.90

*Planned plant turnaround

Production in the first quarter of 2013 averaged 32,531 barrels per day (bpd), compared to 28,446 bpd for the same period in 2012. The 14% increase is the result of expanded steam generation capacity and enhanced reservoir efficiency measures that have allowed additional wells to be placed into production.

Wider deployment of MEG's proprietary reservoir technology began in the first quarter, with three additional wells adapted to enhanced modified steam and gas push technology (eMSAGP) in March and plans to initiate eMSAGP at an additional six wells in the second quarter. MEG's pilot eMSAGP well pattern has demonstrated steam-oil ratios at an industry-leading 1.3, with production volumes remaining steady. New wells utilizing the technology are exhibiting similar initial performance profiles, driving expectations of further efficiencies and incremental production increases.

Net operating costs for the first quarter of 2013 were $10.44 per barrel, compared to $7.95 per barrel for the first three months of 2012. The increase was primarily due to higher natural gas energy prices and higher operational costs associated with MEG's growth strategy and planned near-term production increases. Net operating costs were partially offset by electricity sales revenue from the Corporation's cogeneration facilities.

"Top-quartile operating cost efficiency, increasing production, and our moves to bypass areas of pipeline congestion that have been restricting access to higher priced markets are all coming together. We expect to deliver significantly stronger cash flows as we advance these initiatives in 2013," said McCaffrey.

Cash flow from operations was $7.1 million ($0.03 per share, diluted) for the first quarter of 2013, compared to $72.0 million ($0.36 per share, diluted) for the first quarter of 2012. The decrease in cash flow from operations was primarily due to lower price realizations, particularly in the first two months of the quarter, partially offset by higher production volumes.

MEG recognized a net loss for the first quarter of 2013 of $71.3 million compared to net income of $53.4 million for the first quarter of 2012. The net loss is primarily due to unrealized foreign exchange impacts on the translation of the Corporation's U.S. dollar denominated debt, cash and cash equivalents, as the Canadian dollar decreased in value relative to the U.S. dollar. The recorded net loss in the first quarter was also impacted by the same factors affecting cash flow from operations.

First quarter operating earnings, which are adjusted to exclude unrealized items, were recorded as a loss of $36.7 million ($0.16 per share, diluted) compared to operating earnings of $23.5 million ($0.12 per share, diluted) for the same period in 2012.

Capital and growth strategy

MEG's management believes the company has the financial resources in place, including working capital of $1.3 billion and an additional undrawn US$1.0 billion revolving credit facility, to execute its plan to increase production to 80,000 bpd by early 2015.

The Corporation's remaining budgeted 2013 capital investment totals approximately $1.3 billion, including approximately $135 million deferred from previously planned 2012 investments and will be directed towards:

- The RISER initiative, which is focused on increasing production and throughput capacity in the near-term from existing facilities;

- Drilling and completion of an inventory of stand-by wells to take advantage of freed-up steam from the implementation of eMSAGP;

- Completion of Christina Lake Phase 2B;

- Engineering, long lead items and site preparation for Phase 3A; and

- Infrastructure investments to expand the jointly-owned Access Pipeline and complete the 900,000 barrel Stonefell Terminal in mid-2013, effectively placing MEG's production at the Edmonton transportation hub and providing flexible market transportation options.

"Investments in new reservoir technologies and plant debottlenecking are already showing results – and that's a trend that we expect to continue through the year," said McCaffrey. "We are also beginning to see the results of our marketing initiative, with our first barge shipments aimed at bypassing market congestion already underway. Building on that initiative, we are planning to roll out significant rail transportation volumes in the second half of the year. As we continue through 2013, we expect to deliver increasing volumes to higher-priced markets. The first quarter has set the stage."

Forward-Looking Information and Non-IFRS Financial Measures

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

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the three months ended March 31, 2013 is dated April 23, 2013. This MD&A should be read in conjunction with the Corporation's MD&A for the year ended December 31, 2012, the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2012 and the unaudited condensed consolidated interim financial statements and notes thereto for the period ended March 31, 2013. All tabular amounts are stated in thousands of Canadian dollars ($ or C$) unless indicated otherwise.

MD&A – Table of Contents

1. OVERVIEW

MEG is a corporation focused on sustainable *in situ* oil sands development and production in the southern Athabasca oil sands region of Alberta, Canada. MEG is actively developing enhanced oil recovery projects that utilize steam assisted gravity drainage ("SAGD") extraction methods. MEG is not engaged in oil sands mining.

MEG owns a 100% working interest in over 900 sections of oil sands leases. In a report (the "GLJ Report") dated as at December 31, 2012, GLJ Petroleum Consultants Ltd. ("GLJ") estimated that the oil sands leases it had evaluated contained 2.6 billion barrels of proved plus probable bitumen reserves and 3.4 billion barrels of contingent bitumen resources (best estimate).

The Corporation has identified two commercial SAGD projects; the Christina Lake project and the Surmont project. MEG believes, as supported by estimates in the GLJ Report, that the Christina Lake project can support an average of over 210,000 barrels per day ("bpd") of sustained production for 30 years and that the Surmont project can support an average of 120,000 bpd of sustained production for 20 years. In addition, the Corporation holds additional leases (the “Growth Properties”) that are in the resource definition stage and that could provide significant additional development opportunities.

MEG is currently focused on the phased development of the Christina Lake project. MEG's first two production phases at the Christina Lake project, Phases 1 and 2, commenced production in 2008 and 2009, respectively, with an initial combined design production capacity of 25,000 bpd. Phase 2B, an expansion with an initial design production capacity of 35,000 bpd, is anticipated to be complete in the second half of 2013. In 2012, the Corporation announced the RISER initiative and now expects to reach a total production target from Christina Lake Phases 1, 2, and 2B of approximately 80,000 bpd by early 2015. Phase 3 is expected to be developed in a number of sub-phases. Once Phase 3 is complete, the design production capacity at the Christina Lake Project is expected to reach 210,000 bpd, before including anticipated production increases associated with the RISER initiative. MEG received regulatory authorization to proceed with Phase 3, following approvals issued by the Energy Resources and Conservation Board and by Alberta Environment and Sustainable Development in 2012.

MEG’s Surmont project, which is situated along the same geological trend as Christina Lake, has an anticipated design production capacity of approximately 120,000 bpd over multiple phases. MEG filed a regulatory application for the project in September 2012. The proposed project will use SAGD technology and include multi-well production pads, electricity and steam cogeneration and other facilities similar to MEG’s current Christina Lake project. The project is located approximately 80 kilometers south of Fort McMurray and approximately 50 kilometers north of the Corporation’s Christina Lake operations. This area has been extensively explored and developed for natural gas projects, and more recently for oil sands resources. Other thermal recovery projects are already operating in this area.

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

In addition to Access Pipeline, MEG owns the Stonefell Terminal, a terminal and storage facility currently under construction near Edmonton, Alberta. When complete in mid-2013, the Stonefell Terminal will be connected to the Access Pipeline, and will provide approximately 900,000 bbls of strategic storage capacity, and is expected to provide MEG with access to a variety of markets and with access to multiple sources of diluent.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The following table summarizes selected operational and financial information of the Corporation for the three months ended March 31:

	2013	2012
Bitumen production – bpd	32,531	28,446
Steam to oil ratio (SOR)	2.5	2.5
West Texas Intermediate (WTI) US$/bbl	94.37	102.92
Differential – Blend vs WTI - %	41.9%	31.2%
Bitumen realization - $/bbl	30.04	50.15
Net operating costs(1) - $/bbl	10.44	7.95
Cash operating netback(2) - $/bbl	17.90	39.20
Capital cash investment - $000	668,932	364,862
Net income (loss) - $000	(71,294)	53,369
Per share, diluted	(0.32)	0.27
Operating earnings (loss) - $000(3)	(36,712)	23,529
Per share, diluted(3)	(0.16)	0.12
Cash flow from operations - $000(3)	7,071	71,991
Per share, diluted(3)	0.03	0.36
Cash and short-term investments - $000	1,803,338	1,402,390
Long-term debt - $000	2,823,207	1,718,474

(1) Net operating costs include energy and non-energy operating costs, reduced by power sales. Please refer to Cash Operating Netbacks discussed further under the heading "RESULTS OF OPERATIONS."

(2) Cash operating netbacks are calculated by deducting the related diluent, transportation, field operating costs and royalties from production and power revenues, on a per barrel basis. Please refer to note 3 of the Cash Operating Netbacks table within "RESULTS OF OPERATIONS."

(3) Operating earnings, cash flow from operations and the related per share amounts do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The Corporation uses these non-IFRS measurements for its own performance measures and to provide its shareholders with a measurement of the Corporation's ability to internally fund future capital investments. These non-IFRS measurements are reconciled to net income (loss) and net cash provided by (used in) operating activities in accordance with IFRS under the heading "NON-IFRS MEASUREMENTS" and discussed further in the "ADVISORY" section.

Bitumen production for the three months ended March 31, 2013 averaged 32,531 bpd compared to 28,446 bpd for the same period in 2012. The 14% increase in production is the result of expanded steam generation capacity and reservoir efficiency measures that have allowed additional wells to be placed into production, including three new well pairs and three new infill wells brought into production during the first quarter of 2013. There were 44 SAGD well pairs and five infill wells on production as at March 31, 2013 compared to 36 SAGD well pairs and two infill wells on production as at March 31, 2012.

Bitumen realizations were reduced as increased production of both light crude oil and heavy crude oil put downward pressure on both light and heavy oil prices in North America, particularly in the mid-continent. Pipeline congestion and refinery outages in the U.S. Midwest have added to this pressure, which has led to a higher discount for Canadian crude. The price of West Texas Intermediate ("WTI") decreased to an average of US$94.37 per barrel from US$102.92 per barrel during the first quarter of 2012. The differential between the price of WTI and the Corporation's blend sales price was 41.9% in the first quarter of 2013, compared to 31.2% for the first quarter of 2012. Differentials began to narrow in the month of March, averaging 35.0%.

Net operating costs for the first three months of 2013 were $10.44 per barrel, compared to $7.95 per barrel for the first three months of 2012. The increase in net operating costs was the result of:

- an increase in energy operating costs, primarily as a result of higher natural gas prices which increased from an average of $2.08 per mcf during the first quarter of 2012 to an average of $3.46 per mcf for the first quarter of 2013; and
- an increase in non-energy operating costs, as a result of higher camp and labor costs.

Energy and non-energy operating costs were partially offset by power sales. Power sales had the effect of offsetting 67% of energy operating costs during the first quarter of 2013 compared to 109% during the first quarter of 2012.

Cash operating netback for the three months ended March 31, 2013 was $17.90 per barrel compared to $39.20 per barrel for the same period in 2012. Cash operating netbacks were negatively impacted by the decrease in the Corporation's bitumen realizations in the first quarter of 2013 compared to the first quarter of 2012. The decrease was partially offset by the 14% increase in production for the first three months of 2013 compared to the same period in 2012.

Capital investment increased to $668.9 million during the first quarter of 2013 from $364.9 million during the first quarter of 2012. Capital investment for the first three months of 2013 has focused on the construction of Phase 2B, front-end engineering and design for Phase 3A, delineation drilling at Christina Lake and Surmont, the RISER initiative, construction of the Stonefell Terminal, and expansion of the Access Pipeline.

The Corporation recognized a net loss for the first quarter of 2013 of $71.3 million compared to net income of $53.4 million for the first quarter of 2012. The net loss for the first three months in 2013 included a net foreign exchange loss of $42.1 million, primarily arising from the translation of the Corporation's U.S. dollar denominated debt and U.S. dollar cash and cash equivalents. This compared to a net foreign exchange gain of $28.6 million in the first quarter of 2012. Net income was also impacted by lower realized bitumen prices and higher production volumes in the first quarter of 2013 compared to the first quarter of 2012.

Operating loss for the three months ended March 31, 2013 was $36.7 million compared to operating earnings of $23.5 million for the three months ended March 31, 2012. The decrease in operating earnings for the first quarter of 2013 compared to the same period in 2012 is primarily due to lower bitumen realizations partially offset by higher production.

Cash flow from operations was $7.1 million for the first quarter of 2013, compared to $72.0 million for the first quarter of 2012. Cash flow from operations was impacted by the same factors that impacted operating earnings.

The Corporation's cash and short-term investments balance was $1.8 billion as at March 31, 2013 compared to $1.4 billion as at March 31, 2012. Long-term debt increased to $2.8 billion as at March 31, 2013 from $1.7 billion as at March 31, 2012. On July 19, 2012, the Corporation issued US$800.0 million in aggregate principal amount of 6.375% senior unsecured notes, with interest paid semi-annually. The notes are due on January 30, 2023. On December 28, 2012, the Corporation issued 24.2 million common shares at a price of $33.00 per share for net proceeds of $774.8 million. Effective February 25, 2013, the Corporation re-priced, increased and extended its existing US$987.5 million senior secured term loan. The Corporation extended the maturity date to March 31, 2020 and increased its borrowing under the senior secured term loan by US$300 million. In addition, the Corporation reduced the interest rate on the term loan by 0.25 percent.

As at March 31, 2013, the Corporation's capital resources included $1.8 billion of cash and short-term investments and an undrawn US$1.0 billion revolving credit facility.

3. OUTLOOK

The Corporation anticipates that annual bitumen production volumes for 2013 will be in the 32,000 to 35,000 bpd range, after including the impacts of an approximate two week slowdown for maintenance and tie-in activity in the second quarter of 2013 and the start-up of the Christina Lake Phase 2B project in the second half of 2013. Following the start-up of Christina Lake Phase 2B, production is expected to ramp-up toward a year-end exit rate of 37,000 to 43,000 bpd. Annual non-energy operating costs are anticipated to be in the range of $9 to $11 per barrel.

The Corporation's remaining budgeted 2013 capital investment totals approximately $1.3 billion, including approximately $135 million deferred from previously planned 2012 investments and will be directed towards:

- the RISER initiative, which is focused on increasing production and throughput capacity in the near-term from existing facilities to reach targeted production of 80,000 bpd by early 2015;
- completion of Phase 2B;
- drilling and completion of an inventory of stand-by wells to take advantage of freed-up steam from the implementation of enhanced Modified Steam and Gas Push (eMSAGP);
- engineering, long lead items and site preparation for Phase 3A; and
- infrastructure investments to expand the jointly-owned Access Pipeline and to complete the 900,000 barrel Stonefell Terminal in mid-2013, effectively placing MEG's production at the Edmonton transportation hub and providing flexible market transportation options.

4. BUSINESS ENVIRONMENT

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

	2013	2012				2011		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Commodity Prices (Average Prices)								
Crude oil prices								
West Texas Intermediate (WTI) US$/bbl	94.37	88.18	92.22	93.49	102.92	94.06	89.76	102.56
Western Canadian Select (WCS) C$/bbl	63.01	69.47	70.06	71.34	81.66	85.53	70.68	82.17
Differential – WTI vs WCS (C$/bbl)	32.20	17.94	21.67	23.10	21.39	10.70	17.31	17.08
Differential – WTI vs WCS (%)	33.8%	20.5%	23.6%	24.5%	20.8%	11.1%	19.7%	17.2%
Natural gas prices								
AECO (C$/mcf)	3.18	3.20	2.27	1.89	2.14	3.16	3.64	3.86
Electric power prices								
Alberta power pool average price (C$/MWh)	65.26	78.73	78.09	40.03	60.10	76.05	94.69	51.90
Foreign exchange rates								
C$ equivalent of 1 US$ - average	1.0089	0.9913	0.9948	1.0102	1.0012	1.0231	0.9802	0.9676
C$ equivalent of 1 US$ - period end	1.0156	0.9949	0.9837	1.0191	0.9991	1.0170	1.0389	0.9643

The price of WTI is an important benchmark for Canadian crude oil, as it reflects mid-continent North American prices and its Canadian dollar equivalent is the basis for determining royalties on the Corporation's bitumen sales. The average price for WTI for the first quarter of 2013 was US$94.37 per barrel compared to US$102.92 per barrel for the first quarter of 2012.

Western Canadian Select ("WCS") is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil and condensate. WCS trades at a differential below the WTI benchmark price. During the first quarter of 2013, the WTI/WCS differential averaged 33.8% compared to 20.8% during the first quarter of 2012. The differential narrowed towards the end of the quarter and for the month of March averaged 28.2%.

Increases in production of both light crude oil and heavier crudes have developed more quickly than pipeline transportation additions, resulting in pressure on both light and heavy oil prices in the U.S. Mid-Continent. Resulting pipeline congestion, coupled with refinery outages in the U.S. Midwest, added to this pressure which led to a larger discount for Canadian crude in 2012 and early 2013, relative to world prices. A number of initiatives to access additional markets, including the expansion in capacity of the Seaway pipeline in early 2013; completion of the TransCanada Gulf Coast Pipeline in late 2013; and the completion of the Flanagan South pipeline and Seaway expansion in mid-2014, should help realign Canadian crude prices with those of other crude oil benchmarks over the next 18 to 24 months.

The bitumen the Corporation produces at the Christina Lake project is mixed with purchased diluent and the end product is marketed as a heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). It is shipped through the Access Pipeline to the Edmonton-area refining and transportation hub. MEG has a number of initiatives under way to improve on the market reach of this hub, both in the short and medium term. MEG is expecting to complete construction of its wholly-owned Stonefell Terminal, including a direct pipeline connection to newly expanded third party rail loading facilities at Bruderheim, Alberta and to implement barging along the U.S. Inland Waterways, in mid-2013. These market access initiatives are anticipated to enable MEG to bypass pipeline congestion in the U.S. Midwest and Mid-Continent and shift product pricing from the discounted Edmonton and mid-continent markets to higher priced coastal markets, including most importantly, the U.S. Gulf Coast. In addition, for the medium term, the Corporation has secured strategic pipeline capacity to the U.S. Gulf Coast commencing in mid-2014.

Natural gas is a primary energy input cost for the Corporation, as it is used to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facility. The benchmark AECO natural gas price averaged $3.18 per mcf during the first three months of 2013, compared to $2.14 per mcf during the first three months of 2012. Prices in the first quarter of 2013 were higher than the same period in 2012 as cold weather in the United States caused strong heating demand, and resulted in U.S. storage levels falling below first quarter 2012 levels.

The Alberta power pool price averaged $65.26 per megawatt hour for the three months ended March 31, 2013, compared to $60.10 per megawatt hour for the same period in 2012. The increase in power prices is largely attributable to the supply and demand of power within the province of Alberta.

Changes in the value of the Canadian dollar relative to the U.S. dollar have an impact on the Corporation's bitumen revenues, as sales prices are determined by reference to U.S. benchmarks, and on principal and interest payments on the Corporation's U.S. dollar denominated debt. An increase in the value of the Canadian dollar compared to the U.S. dollar has a negative impact on bitumen revenues and a positive impact on principal and interest payments, while a decrease in value has a positive impact on bitumen revenues and a negative impact on principal and interest payments. As at March 31, 2013, the Canadian dollar, at a rate of 1.0156, had decreased in value by approximately $0.02 against the U.S. dollar compared to its value as at December 31, 2012, when the rate was 0.9949.

5. RESULTS OF OPERATIONS

	Three months ended March 31	
	2013	**2012**
Bitumen production – bpd	32,531	28,446
Steam to oil ratio	2.5	2.5

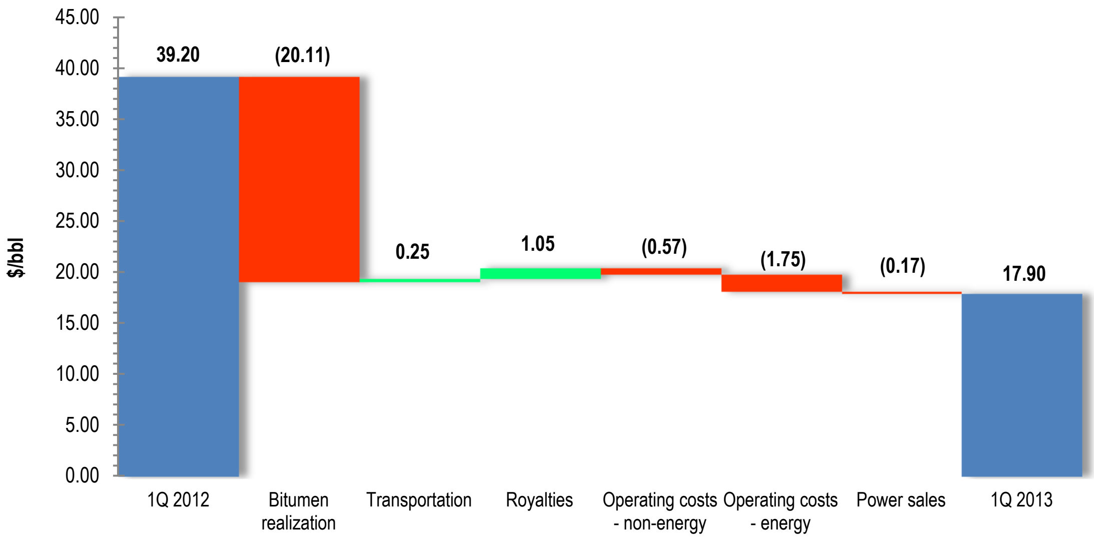
Production

Production averaged 32,531 bpd for the first quarter of 2013, compared to 28,446 bpd for the first quarter of 2012. The increase in production is the result of expanded steam generation capacity and reservoir efficiency measures that have allowed additional wells to be placed into production, including three new well pairs and three new infill wells brought into production during the first quarter of 2013. There were 44 SAGD well pairs and five infill wells on production as at March 31, 2013, in comparison to 36 SAGD well pairs and two infill wells on production as at March 31, 2012.

The SOR for the first three months of 2013 was 2.5, consistent with the first three months of 2012. The Corporation continues to focus on increasing production and improving efficiency of current production through a lower SOR, which is an important efficiency indicator that measures the amount of steam that is injected into the reservoir in relation to bitumen produced.

Cash Operating Netback

Bridge analysis of cash operating netback for the three months ended March 31, 2013 versus March 31, 2012:



The following table summarizes the Corporation's cash operating netback for the three months ended March 31:

	2013		2012	
	$000	**$ per bbl**	**$000**	**$ per bbl**
Bitumen realization(1)	87,589	30.04	130,380	50.15
Transportation(2)	(360)	(0.12)	(954)	(0.37)
Royalties	(4,602)	(1.58)	(6,834)	(2.63)
Net bitumen revenue	**82,627**	**28.34**	**122,592**	**47.15**
Operating costs – non-energy	(25,682)	(8.81)	(21,418)	(8.24)
Operating costs – energy	(14,359)	(4.93)	(8,264)	(3.18)
Power sales	9,616	3.30	9,026	3.47
Net operating costs	**(30,425)**	**(10.44)**	**(20,656)**	**(7.95)**
Cash operating netback(3)	**52,202**	**17.90**	**101,936**	**39.20**

(1) *Net of diluent costs. For further details, refer to the "Bitumen realization" section.*

(2) *Net of third-party recoveries on diluent transportation arrangements. For further details, refer to the "Transportation" section.*

(3) *Cash operating netbacks are calculated by deducting the related diluent, transportation, field operating costs and royalties from production and power revenues. Netbacks on a per-unit basis are calculated by dividing related production revenue, costs and royalties by bitumen sales volumes. Netbacks do not have a standardized meaning prescribed by IFRS and, therefore, may not be comparable to similar measures used by other companies. This non-IFRS measurement is widely used in the oil and gas industry as a supplemental measure of the Corporation's efficiency and its ability to fund future growth through capital expenditures. "Cash operating netback" is reconciled to "Net income (loss)," the nearest IFRS measure, under the heading "NON-IFRS MEASUREMENTS."*

Bitumen realization

Bitumen produced at the Christina Lake project is mixed with purchased diluent and sold as bitumen blend. Bitumen realization as discussed in this MD&A represents the Corporation's realized revenues, net of the cost of diluent.

	Three months ended March 31	
($000)	**2013**	**2012**
Blend sales – proprietary volumes	241,800	274,295
Cost of diluent	(154,211)	(143,915)
Bitumen realization	87,589	130,380

Blend sales for the three months ended March 31, 2013 were $241.8 million compared to $274.3 million for the three months ended March 31, 2012. Blend sales averaged $55.24 per barrel for the first quarter of 2013 compared to $70.95 per barrel for the first quarter of 2012. The decrease in blend sales is due to the lower average realized price partially offset by the increase in sales volumes.

The cost of diluent was $154.2 million for the three months ended March 31, 2013, compared to $143.9 million for the same period in 2012. On a per barrel basis, the Corporation's cost of diluent decreased to $105.51 per barrel for the first quarter of 2013, from $113.62 per barrel for the first quarter of 2012. The total cost of diluent increased due to higher volumes of diluent purchased as a result of increased bitumen production, partially offset by the decrease in average diluent prices.

Transportation

Transportation costs, which primarily consist of MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries, were $0.4 million for the first three months of 2013 compared to $1.0 million for the first three months of 2012. On a per barrel basis, transportation costs decreased to an average of $0.12 per barrel during the three months ended March 31, 2013, from $0.37 per barrel during the three months ended March 31, 2012. The decrease in transportation costs in the first quarter of 2013 compared to the first quarter of 2012 is due to the increase in recoveries from diluent transportation arrangements. In the first quarter of 2013, the Corporation recognized third-party recoveries of $5.4 million compared to $3.1 million in the first quarter of 2012.

Royalties

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

Royalties were $4.6 million for the first quarter of 2013 compared to $6.8 million for the first quarter of 2012, or an average of $1.58 per barrel for the first quarter of 2013, compared to $2.63 per barrel for the first quarter of 2012. The decrease in royalties is attributable to lower bitumen realizations.

Operating Costs

Non-energy related operating costs were $25.7 million for the three months ended March 31, 2013, compared to $21.4 million for the three months ended March 31, 2012 and increased to an average of $8.81 per barrel from $8.24 per barrel for the first quarter of 2012. The increase in non-energy related operating costs is primarily attributable to higher camp and labor costs, which were largely offset on a per barrel basis by the increase in production.

Energy related operating costs were $14.4 million for the three months ended March 31, 2013 compared to $8.3 million for the three months ended March 31, 2012. On a per barrel basis, energy operating costs were $4.93 per barrel for the three months ended March 31, 2013 compared to $3.18 per barrel for the same period in 2012. The increase in energy related operating costs per barrel is primarily the result of higher natural gas prices. The benchmark AECO natural gas price averaged $3.18 per mcf for the first quarter of 2013, compared to $2.14 per mcf for the first quarter of 2012. Natural gas prices in the first quarter of 2013 were higher than the same period in 2012 as cold weather in the United States caused strong heating demand and resulted in US storage levels falling below first quarter 2012 levels.

Power Sales

The Corporation's 85 megawatt cogeneration facility produces approximately 70% of the steam for current SAGD operations. MEG's Christina Lake facilities utilize the heat produced by the cogeneration facility and approximately 11 to 13 megawatts of the power generated. Surplus power is sold into the Alberta power pool.

Power sales were $9.6 million for the first three months of 2013, compared to $9.0 million for the first three months of 2012. The Corporation realized an average power price of $59.92 per megawatt hour for the three months ended March 31, 2013, compared to $58.25 per megawatt hour for the three months ended March 31, 2012. Variations in the Corporation's realized power prices during the periods are largely consistent with variations in the Alberta power pool prices during the periods noted. The increase in power prices is largely attributable to the supply and demand of power within the province of Alberta.

6. NON-IFRS MEASUREMENTS

The following tables reconcile the non-IFRS measurements "Operating earnings" and "Cash operating netback" to "Net income (loss)", the nearest IFRS measure, and also reconcile the non-IFRS measurement "Cash flow from operations" to "Net cash provided by (used in) operating activities", the nearest IFRS measure. Operating earnings is defined as net income (loss) as reported, excluding the after-tax unrealized foreign exchange gains and losses and unrealized gains and losses on derivative financial liabilities. Cash flow from operations excludes the net change in non-cash operating working capital, while the IFRS measurement "Net cash provided by (used in) operating activities" includes these items. Cash operating netback is comprised of proprietary petroleum and power sales less royalties, operating costs, cost of diluent and transportation costs.

	Three months ended March 31	
($000)	**2013**	**2012**
Net income (loss)	(71,294)	53,369
Add (deduct):		
Unrealized foreign exchange (gain) loss, net of tax[1]	37,810	(28,996)
Unrealized (gain) loss on derivative financial liabilities, net of tax[2]	(3,228)	(844)
Operating earnings (loss)	(36,712)	23,529
Add (deduct):		
Interest income	(5,271)	(5,549)
Depletion and depreciation	44,415	34,786
General and administrative	22,767	14,731
Stock-based compensation	6,955	5,334
Research and development	1,283	1,294
Interest expense	25,089	19,707
Accretion	1,076	833
Gain on disposition of asset	-	(3,075)
Realized (gain) loss on foreign exchange	1,228	(367)
Realized loss on derivative financial liabilities	1,101	1,060
Net marketing activity	233	-
Deferred income tax expense (recovery), operating	(9,962)	9,653
Cash operating netback	52,202	101,936

(1) Unrealized foreign exchange gains and losses result primarily from the translation of U.S. dollar denominated long-term debt and cash and cash equivalents to period-end exchange rates. Unrealized foreign exchange gains and losses are presented net of a deferred tax recovery of $3,107 for the three months ended March 31, 2013 (deferred tax recovery of $762 for the three months ended March 31, 2012).

(2) Unrealized gains and losses on derivative financial liabilities result from the interest rate floor on the Corporation's long-term debt and interest rate swaps entered into to fix a portion of its variable rate long-term debt, net of a deferred tax expense of $1,076 for the three months ended March 31, 2013 (deferred tax recovery of $282 for the three months ended March 31, 2012).

	Three months ended March 31	
Non-IFRS Measurements - Reconciliation of net cash provided by (used in) operating activities to cash flow from operations ($000)	**2013**	**2012**
Net cash provided by (used in) operating activities	(24,992)	41,558
Add:		
Net change in non-cash operating working capital items	32,063	30,433
Cash flow from operations	7,071	71,991

Depletion and Depreciation

Depletion and depreciation expense was $44.4 million for the three months ended March 31, 2013, compared to $34.8 million for the same period in 2012. The increase is primarily due to higher production volumes and an increase in the rate per barrel as a result of an increase in GLJ’s estimate of future development costs of the producing oil sands properties. The future development costs are a key element of the rate determination. The depletion and depreciation rate for the three months ended March 31, 2013 was $15.16 per barrel, compared to $13.44 per barrel for the three months ended March 31, 2012. The Corporation's producing oil sands properties are depleted on a unit of production basis based on estimated proved reserves. Major facilities and equipment are depreciated on a unit of production basis over the estimated total productive capacity of the facilities and equipment. Pipeline assets are depreciated on a straight-line basis over their estimated useful lives.

General and Administrative Costs

	Three months ended March 31	
($000)	**2013**	**2012**
General and administrative costs	28,647	19,145
Capitalized general and administrative costs	(5,880)	(4,414)
General and administrative expense	22,767	14,731

General and administrative expense for the three months ended March 31, 2013 was $22.8 million, compared to $14.7 million for the same period in 2012. The increase in expense is primarily the result of the planned growth in the Corporation's professional staff and office costs to support the operation and development of its oil sands assets.

Stock-based Compensation

The fair value of compensation associated with the granting of stock options and restricted share units ("RSUs") to employees, contractors and directors is recognized by the Corporation in its consolidated financial statements. Fair value is determined using the Black-Scholes option pricing model. Stock-based compensation expense was $7.0 million for the three months ended March 31, 2013, compared to $5.3 million for the three months ended March 31, 2012. The Corporation capitalizes a portion of stock-based compensation expense associated with capitalized salaries and benefits. The Corporation capitalized $1.7 million of stock-based compensation to property, plant and equipment during the three months ended March 31, 2013, compared to $1.5 million during the three months ended March 31, 2012.

Research and Development

Research and development expenditures related to the Corporation's research of crude quality improvement and related technologies have been expensed. Research and development expenditures were $1.3 million in each of the three month periods ended March 31, 2013 and March 31, 2012.

Net Finance Expense

	Three months ended March 31	
($000)	**2013**	**2012**
Total interest expense	38,723	24,250
Less capitalized interest	(13,634)	(4,543)
Net interest expense	25,089	19,707
Accretion on decommissioning provision	1,076	833
Unrealized fair value (gain) loss on embedded derivative financial liabilities	(3,075)	(2,458)
Unrealized fair value (gain) loss on interest rate swaps	(1,229)	1,332
Realized loss on interest rate swaps	1,101	1,060
Net finance expense	22,962	20,474

Total interest expense was $38.7 million for the three months ended March 31, 2013, compared to $24.3 million for the three months ended March 31, 2012. Total interest expense increased primarily as a result of the increased debt outstanding. Effective July 19, 2012, the Corporation issued US$800.0 million of 6.375% senior unsecured notes. Effective February 25, 2013, the Corporation increased its senior secured term loan by US$300 million to US$1.3 billion.

The Corporation recognized an unrealized gain on embedded derivative financial liabilities of $3.1 million during the first quarter of 2013, compared to a gain of $2.5 million during the first quarter of 2012. These gains relate to the change in fair value of the interest rate floor associated with the Corporation's senior secured credit facilities. The interest rate floor is considered an embedded derivative as the floor rate was higher than the London Interbank Offered Rate ("LIBOR") at the time that the debt agreements were entered into. Accordingly, the original fair value of the embedded derivatives at the time the debt agreements were entered into were netted against the carrying value of the long-term debt and are amortized over the life of the debt agreements. The fair value of the embedded derivative is included in derivative financial liabilities on the balance sheet and gains and losses associated with changes in the fair value of the embedded derivative are included in net finance expense.

The Corporation has entered into interest rate swap contracts to fix the interest rate at approximately 4.6% on US$748.0 million of the US$1.3 billion senior secured term loan until September 30, 2016. The Corporation realized a $1.1 million loss for each of the three month periods ended March 31, 2013 and 2012. In addition, the Corporation recognized a $1.2 million unrealized gain on the interest rate swaps during the three months ended March 31, 2013, compared to a $1.3 million unrealized loss during the same period in 2012.

Net Foreign Exchange Gain (Loss)

	Three months ended March 31	
($000)	**2013**	**2012**
Foreign exchange gain (loss) on:		
Long-term debt	(49,256)	31,280
US$ denominated cash and cash equivalents	8,339	(3,046)
Other	(1,228)	367
Net foreign exchange gain (loss)	(42,145)	28,601

C$-US$ exchange rate as at	**March 31, 2013**	**December 31, 2012**	**March 31, 2012**	**December 31, 2011**
C$ equivalent of 1 US$	1.0156	0.9949	0.9991	1.0170

The net foreign exchange loss for the three months ended March 31, 2013 was $42.1 million in comparison to a net foreign exchange gain of $28.6 million for the three months ended March 31, 2012. The Canadian dollar weakened by approximately $0.02 during the first three months of 2013, while it strengthened by approximately $0.02 during the first three months of 2012.

Net Marketing Activity

	Three months ended March 31	
($000)	**2013**	**2012**
Sales of purchased product	5,778	-
Purchased product and storage	(6,011)	-
Net marketing activity	(233)	-

The Corporation is securing pipeline capacity and pursuing opportunities to move products to a wider range of markets through the development of proprietary transportation and storage facilities.

Income Taxes

The Corporation recognized a deferred income tax recovery of $12.0 million for the three months ended March 31, 2013, compared to a deferred income tax expense of $9.2 million for the three months ended March 31, 2012.

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

- The non-taxable portion of capital foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt is a permanent difference. For the three months ended March 31, 2013, the non-taxable loss was $24.6 million compared to a non-taxable gain of $15.6 million for the same period in 2012.

- As at March 31, 2013, the Corporation had not recognized the tax benefit related to $3.9 million in unrealized taxable capital foreign exchange losses.

- Non-taxable stock-based compensation expense was $7.0 million for the first quarter of 2013, in comparison to $5.3 million for the first quarter of 2012.

The Corporation is not currently taxable. As of March 31, 2013, the Corporation had approximately $3.9 billion of available tax pools and had recognized a deferred income tax liability of $59.6 million. In addition, at March 31, 2013, the Corporation had $2.2 billion of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

7. SUMMARY OF QUARTERLY RESULTS

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

	2013	2012				2011		
($ millions, except per share amounts)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Revenue	258.0	297.6	213.7	259.7	279.6	326.5	175.9	279.9
Net income (loss)	(71.3)	(18.7)	47.5	(29.5)	53.4	91.1	(115.2)	42.5
Per share – basic	(0.32)	(0.09)	0.24	(0.15)	0.28	0.47	(0.60)	0.22
Per share – diluted	(0.32)	(0.09)	0.24	(0.15)	0.27	0.46	(0.60)	0.21

Revenue for the eight most recent quarters has been impacted by an increase in production and fluctuations in blend sales pricing. Lower revenues in the third quarters of 2012 and 2011 were due to reduced production as the result of scheduled turnarounds at the Christina Lake facilities.

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

- foreign exchange gains and losses attributable to fluctuations in the rate of exchange between the Canadian and U.S. dollar in translating the Corporation's U.S. dollar denominated debt (net of U.S. dollar denominated cash and short-term investments);

- changes in the fair value of the LIBOR floor on the senior secured term loans (embedded derivative financial liability);
- an increase in depletion and depreciation expense as a result of the increase in production and estimated future development costs;
- risk management activities for interest rate swaps;
- the scheduled plant turnarounds performed in September 2012 and September 2011;
- higher general and administrative expense as a result of the planned increase in office staff to support growth; and
- an increase in interest expense as a result of the increase in long-term debt.

8. CAPITAL INVESTING

	Three months ended March 31	
Summary of capital investment ($000)	**2013**	**2012**
Christina Lake Phase 2B	101,274	173,875
Christina Lake Phase 3A	92,904	3,951
RISER and other enhancements	114,392	19,692
Inventory wells	50,576	1,964
Delineation drilling and seismic	82,481	87,946
Regulatory	390	3,289
Other	18,320	6,390
Growth	**460,337**	**297,107**
Access Pipeline	91,016	32,413
Stonefell Terminal	62,792	11,598
Field infrastructure	18,758	10,209
Infrastructure related to growth	**172,566**	**54,220**
Sustaining	10,502	5,479
Capitalized interest	13,634	4,543
Other	11,893	3,513
Total cash capital investment	**668,932**	**364,862**
Non-cash	12,939	6,232
Total capital investment	**681,871**	**371,094**

MEG's capital investment for the three months ended March 31, 2013 totalled $681.9 million, compared to $371.1 million invested during the three months ended March 31, 2012. Capital investment included $460.3 million in growth focused investment during the first quarter of 2013, compared to $297.1 million in 2012.

MEG invested $101.3 million on Phase 2B of the Christina Lake project during the first quarter of 2013, which was directed towards the purchase of materials and construction activities. As at March 31, 2013, detailed engineering was complete and all modules had been installed, with on-site construction scheduled to continue toward targeted completion and start-up in the second half of 2013.

For the three months ended March 31, 2013, the Corporation invested $92.9 million on engineering, purchasing of long-lead equipment and materials, and site preparation activity for the Phase 3A central processing plant of the Christina Lake project.

MEG invested $114.4 million during the first three months of 2013 on RISER, which included the drilling of twelve infill wells, and other operational enhancements and $50.6 million for the drilling of inventory wells at the Christina Lake project. This included the drilling of eight additional SAGD well pairs. These activities are aimed at further improving the operational performance of the Corporation's wells and facilities.

For the three months ended March 31, 2013, the Corporation invested $82.5 million on delineation drilling. The Corporation drilled 131 stratigraphic wells, one water observation well and four water source wells to support horizontal well placement and to further delineate the resource base at Christina Lake. A total of 24 stratigraphic wells, one water source well and three water test wells were completed at Surmont.

A total of $172.6 million was invested in the Corporation's growth-related infrastructure during the first quarter of 2013. Of this total, the Corporation invested $91.0 million, primarily on material purchases and construction related to the expansion of the 50% owned Access Pipeline. Regulatory approval of the pipeline expansion was received in 2012 and 80 kilometers of the 300 kilometer pipeline have been installed. Investment in the Stonefell Terminal was $62.8 million during the first quarter of 2013. The Stonefell Terminal is a 900,000 barrel tank farm, connected to the Access Pipeline near the Access Pipeline Sturgeon Terminal, and is expected to be operational in mid-2013. The Corporation invested a total of $18.8 million in support infrastructure for current and future operations at Christina Lake.

The Corporation capitalizes interest expense associated with qualifying assets. During the three months ended March 31, 2013, $13.6 million was capitalized, in comparison to $4.5 million during the three months ended March 31, 2012.

Other investments include amounts paid to maintain the right to participate in a potential pipeline project and investments in administrative assets.

Non-cash capital investment for future reclamation and decommissioning of the Corporation's property, plant and equipment and capitalized stock based compensation was $12.9 million for the three months ended March 31, 2013, compared to $6.2 million for the three months ended March 31, 2012.

9. LIQUIDITY AND CAPITAL RESOURCES

	As at March 31	
($000, except as noted)	**2013**	**2012**
Cash and short-term investments	1,803,338	1,402,390
Senior secured term loan (March 31, 2013 - US$1.284 billion; March 31, 2012 – US$997.5 million; due 2020)	1,304,284	994,105
US$1.0 billion revolver due 2017	-	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	761,700	749,325
6.375% senior unsecured notes (US$800.0 million; due 2023)	812,480	-
Total debt(1)	2,878,464	1,743,430
Shareholders' equity	4,817,253	4,049,633
Total book capitalization(2)	7,695,717	5,793,063
Total debt/book capitalization(2)	37.4%	30.1%

(1) *Total debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The Corporation uses this non-IFRS measurement to analyze leverage and liquidity. Total debt less the current portion of the senior secured term loan, unamortized financial derivative liability discount and unamortized deferred debt issue costs is equal to long term debt as reported in the Corporation's consolidated financial statements as at March 31, 2013 and 2012.*

(2) *Non-IFRS measurements and related metrics that use total debt plus shareholders' equity.*

Capital Resources

As at March 31, 2013, the Corporation's capital resources included $1.3 billion of working capital and an additional undrawn US$1.0 billion revolving credit facility. Working capital is comprised of $1.8 billion of cash, cash equivalents and short-term investments, offset by a non-cash working capital deficiency of $0.5 billion.

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the development of Phase 2B and the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary. The Corporation's cash flow and the development of Phase 2B and other projects are dependent on factors discussed in the "RISK FACTORS" section below.

On February 25, 2013, the Corporation re-priced, increased and extended its US$987.5 million senior secured term loan. The Corporation extended the maturity date to March 31, 2020 and increased its borrowing under the senior secured term loan by US$300 million. In addition, the Corporation reduced the interest rate on the term loan by 25 basis points. The amended US$1.2875 billion term loan bears a floating interest rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 175 or 275 basis points, respectively, and an interest rate floor of 200 basis points based on U.S. Prime or 100 basis points based on LIBOR. The term loan is being repaid in quarterly installments of US$3.250 million which commenced March 28, 2013, with the balance due March 31, 2020. The $7.2 million cost of the transaction has been deferred and is being amortized over the term of the revolver.

On December 28, 2012, the Corporation issued 24.2 million common shares at a price of $33.00 per share for net proceeds of $774.8 million.

On July 19, 2012, the Corporation issued US$800.0 million in aggregate principal amount of 6.375% senior unsecured notes, with interest paid semi-annually. The notes are due on January 30, 2023. The $13.6 million cost of the transaction has been deferred and is being amortized over the life of the notes.

On March 21, 2012 MEG expanded its senior secured revolving credit facility from US$500.0 million to US$1.0 billion. In addition, the Corporation extended the maturity of the revolving credit facility by one year to March 21, 2017. The transaction was completed through an amendment of MEG's existing credit facility. The $5.6 million cost of the transaction has been deferred and is being amortized over the term of the revolver.

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. The Corporation has entered into interest rate swap contracts to fix the interest rate at approximately 4.6% on US$748.0 million of the US$1.3 billion senior secured term loan until September 30, 2016.

The Corporation's cash and short-term investments are held in accounts with a diversified group of highly-rated third party financial institutions and consist of invested cash and cash equivalents in the Corporation's operating accounts. The cash is invested in high grade liquid short-term instruments such as government, commercial and bank paper, term deposits, and high interest savings accounts. To date, the Corporation has experienced no material loss or lack of access to its cash in operating accounts, invested cash or cash equivalents. However, the Corporation can provide no assurance that access to its invested cash and cash equivalents will not be impacted by adverse conditions in the financial markets. While the Corporation monitors the cash balances in its operating and investment accounts according to its investment policy and adjusts the cash balances as appropriate, these cash balances could be impacted if the underlying financial institutions or corporations fail or are subject to other adverse conditions in the financial markets.

Cash Flows Summary

	Three months ended March 31	
($000)	**2013**	**2012**
Net cash provided by (used in):		
Operating activities	(24,992)	41,558
Investing activities	(80,326)	(171,628)
Financing activities	306,946	(3,111)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	8,339	(3,046)
Change in cash and cash equivalents	209,967	(136,227)

Cash Flows - Operating Activities

Net cash used in operating activities during the three months ended March 31, 2013 was $25.0 million compared to net cash provided by operating activities of $41.6 million during the three months ended March 31, 2012. The decrease in cash flows from operating activities was primarily due to lower bitumen realizations, higher operating expenses, higher general and administrative expense and higher interest expense, partially offset by the increase in production.

Cash Flows - Investing Activities

Net cash used for investing activities during the first quarter of 2013 primarily consists of $668.9 million in cash capital investment (refer to the "CAPITAL INVESTING" section of this MD&A for further details) offset by a $590.5 million increase in non-cash investing working capital. The majority of the change in non-cash working capital relates to the decrease in short-term investments from $533.0 million at December 31, 2012 to $118.5 million at March 31, 2013.

Net cash used for investing activities during the first quarter of 2012 consists of $364.9 million in cash capital investment, $7.5 million in proceeds from the disposition of assets and a $185.9 million increase in non-cash working capital.

Cash Flows - Financing Activities

Net cash provided by financing activities for the three months ended March 31, 2013 primarily consists of $308.0 million in proceeds from the increase in the senior secured term loan and $9.0 million in proceeds received from the exercise of stock options. These amounts were partially offset by $3.3 million in debt principal repayment on the senior secured term loan and $7.2 million in fees associated with amendments to the senior secured term loan.

Financing activities during the three months ended March 31, 2012 included $5.3 million in proceeds received from the exercise of stock options, offset by $2.5 million of debt principal repayment on the senior secured term loan and $6.0 million of fees associated with the revolving credit facility amendment.

10. SHARES OUTSTANDING

As at March 31, 2013, the Corporation had the following share capital instruments outstanding:

Common shares	221,256,401
Convertible securities	
Stock options outstanding – exercisable and unexercisable	8,068,099
Restricted share units outstanding	946,679

As at April 15, 2013, the Corporation had 221,303,151 common shares, 8,021,349 stock options and 944,185 restricted share units outstanding.

11. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

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

($000)	Total	< 1 year	1 – 3 years	4 – 5 years	More than 5 years
Long-term debt[(1)]	2,878,464	13,203	26,406	26,406	2,812,449
Interest on long-term debt[(1)]	1,180,955	149,970	298,453	296,473	436,059
Decommissioning obligation[(2)]	235,720	3,444	3,784	-	228,492
Pipeline transportation[(3)]	1,430,540	8,636	70,271	124,310	1,227,323
Contracts and purchase orders[(4)]	1,354,406	1,175,688	112,298	25,156	41,264
Operating leases[(5)]	405,520	10,982	22,279	43,587	328,672
	7,485,605	1,361,923	533,491	515,932	5,074,259

(1) *This represents the scheduled principal repayment of the senior secured credit facility and the senior unsecured notes and associated interest payments based on interest rates in effect on March 31, 2013.*

(2) *This represents the undiscounted future obligation associated with the decommissioning of the Corporation's oil and gas properties and facilities.*

(3) *This represents pipeline usage and storage commitments from 2013 to 2028.*

(4) *This represents the future commitment associated with the Corporation's capital program, diluent purchases, and other operating and maintenance commitments.*

(5) *This represents the future commitment for the Calgary corporate office.*

12. NEW ACCOUNTING POLICIES

The Corporation has adopted the following new and revised standards, along with all consequential amendments, effective January 1, 2013. These changes are made in accordance with the applicable transitional provisions.

IFRS 10, Consolidated Financial Statements, replaces the guidance on control and consolidation in IAS 27, Consolidated and Separate Financial Statements, and SIC-12, Consolidation – Special Purpose Entities. IFRS 10 requires consolidation of an investee only if the investor possesses power over the investee, has exposure to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect its returns. Detailed guidance is provided on applying the definition of control. The accounting requirements for consolidation have remained largely consistent with IAS 27. The Corporation assessed its consolidation conclusions on January 1, 2013 and determined that the adoption of IFRS 10 did not result in any change in the consolidation status of its wholly-owned subsidiary, MEG Energy (U.S.) Inc.

IFRS 11, Joint Arrangements, supersedes IAS 31, Interests in Joint Ventures, and requires joint arrangements to be classified either as joint operations or joint ventures depending on the contractual rights and obligations of each investor that jointly controls the arrangement. For joint operations, a company recognizes its share of assets, liabilities, revenues and expenses of the joint operation. An investment in a joint venture is accounted for using the equity method as set out in IAS 28, Investments in Associates and Joint Ventures (amended in 2011). The other amendments to IAS 28 did not affect the Corporation. The Corporation classified its joint arrangements in accordance with IFRS 11 on January 1, 2013 and concluded that the adoption of the standard did not result in any changes in the accounting for its joint arrangements.

IFRS 13, Fair value measurement, provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. Under IFRS 13 the fair value of a liability must reflect the effect of non-performance risk, which includes an entity’s own credit risk. Upon adoption of IFRS 13 the Corporation began including an estimate of its own credit risk in determining the fair value of its derivative financial liabilities. The Corporation adopted IFRS 13 and the required change in valuation techniques on January 1, 2013 on a prospective basis. Upon adoption of IFRS 13, derivative financial liabilities decreased by $1.8 million.

The Corporation has adopted the amendments to IAS 1, Presentation of Financial Statements, effective January 1, 2013. These amendments required the Corporation to group other comprehensive income items by those that will be reclassified subsequently to profit or loss and those that will not be reclassified. These changes did not result in any adjustments to other comprehensive income or comprehensive income.

The Corporation has adopted the amendments to IAS 19, Employee Benefits, effective January 1, 2013. These amendments make significant changes to the recognition and measurement of defined benefit pension expense and termination benefits and to enhance the disclosure of all employee benefits. The adoption of these amendments did not have an impact on the Corporation’s consolidated financial statements.

13. CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Property, Plant and Equipment

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

Exploration and Evaluation Assets

Pre-exploration costs incurred before the Corporation obtains the legal right to explore an area are expensed. Exploration and evaluation costs associated with the Corporation's oil sands activities are capitalized. These costs are accumulated in cost centres pending determination of technical feasibility and commercial viability at which point the costs are transferred to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. The determination of proved or probable reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Impairments

The carrying amounts of the Corporation's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated. An impairment test is completed each year for intangible assets that are not yet available for use. Exploration and evaluation assets are assessed for impairment when they are reclassified to property, plant and equipment or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

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

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves. Fair value less costs to sell is defined as the amount obtainable from the sale of an asset or CGU in an arm's length transaction between knowledgeable, willing parties, less the costs of disposal.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized within net income during the period in which they arise. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the CGU on a pro rata basis.

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

Bitumen Reserves

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the cost and timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Corporation expects that over time its reserves estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion and depreciation charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of oil sands property, plant and equipment carrying amounts.

Decommissioning Provision

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

Deferred Income Taxes

The Corporation recognizes deferred income taxes in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date. The periods in which timing differences reverse are impacted by future earnings and capital expenditures. Rates are also affected by changes to tax legislation.

Stock-based Compensation

Amounts recorded for stock-based compensation expense are based on the historical volatility of the Corporation's share price and those of similar publicly listed enterprises, which may not be indicative of future volatility. Accordingly, these amounts are subject to measurement uncertainty.

Derivative Financial Instruments

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

14. OFF-BALANCE SHEET ARRANGEMENTS

At March 31, 2013 and December 31, 2012, the Corporation did not have any off-balance sheet arrangements.

15. RISK FACTORS

The Corporation's primary focus is on the ongoing development and operation of its oil sands assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including the risks which have been categorized and described in the Corporation's MD&A for the year ended December 31, 2012. In addition, MEG is also subject to other risks and uncertainties which are described in the Corporation's Annual Information Form dated February 27, 2013 under the heading "Regulatory Matters" and "Risk Factors".

16. DISCLOSURE CONTROLS AND PROCEDURES

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

17. INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

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

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

18. ADVISORY

Forward-Looking Information

This MD&A may contain forward-looking information including but not limited to: expectations of future production, revenues, cash flow, operating costs, SORs, pricing differentials, reliability, profitability and capital investments; estimates of reserves and resources; the anticipated reductions in operating costs as a result of optimization and scalability of certain operations; the anticipated capital requirements, timing for receipt of regulatory approvals, development plans, timing for completion, capacities and performance of the Access Pipeline expansion, the RISER initiative, the Stonefell Terminal, third party barging and rail facilities, the future phases and expansions of the Christina Lake project, the Surmont project and potential projects on the Growth Properties; 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 (including the amount, nature and sources of funding thereof), 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 (e.g. operational risks and delays in the development, exploration or production associated with MEG's projects; the securing of adequate supplies and access to markets and transportation infrastructure; the availability of capacity on the electrical transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and revenues; health, safety and environmental risks; risks of legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws), assumptions regarding and the volatility of commodity prices and foreign exchange rates; and risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the continued expansion of the Christina Lake project and the development of the Corporation's other projects and facilities. 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. The forward-looking information included in this MD&A is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this MD&A 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. For more information regarding forward-looking information see “Notice Regarding Forward Looking Information”, "Risk Factors" and "Regulatory Matters" within MEG’s Annual Information Form dated February 27, 2013 (the “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 (www.sedar.com) or by contacting MEG's investor relations department.

Estimates of Reserves and Resources

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

Non-IFRS Financial Measures

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as net bitumen revenue, operating earnings, cash flow from operations and cash operating netback. These financial measures are not defined by IFRS as issued by the International Accounting Standards Board and therefore are referred to as non-IFRS measures. The non-IFRS measures used by the Corporation may not be comparable to similar measures presented by other companies. The Corporation uses these non-IFRS measures to help evaluate its performance. Management considers net bitumen revenue, operating earnings and cash operating netback important measures as they indicate profitability relative to current commodity prices. Management uses cash flow from operations to measure the Corporation's ability to generate funds to finance capital expenditures and repay debt. These non-IFRS measures should not be considered as an alternative to or more meaningful than net income (loss) or net cash provided by (used in) operating activities, as determined in accordance with IFRS, as an indication of the Corporation's performance. The non-IFRS operating earnings and cash operating netback measures are reconciled to net income (loss), while cash flow from operations is reconciled to net cash provided by (used in) operating activities.

19. 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.

20. QUARTERLY SUMMARIES

	2013	2012				2011		
Unaudited	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
FINANCIAL ($000 unless specified)								
Net income (loss)	(71,294)	(18,740)	47,474	(29,534)	53,369	91,118	(115,196)	42,537
Per share, diluted	(0.32)	(0.09)	0.24	(0.15)	0.27	0.46	(0.60)	0.21
Operating earnings (loss)	(36,712)	(538)	(12,883)	11,134	23,529	57,833	(5,917)	36,474
Per share, diluted	(0.16)	0.00	(0.07)	0.06	0.12	0.29	(0.03)	0.18
Cash flow from operations	7,071	56,106	24,442	59,975	71,991	121,608	25,478	88,204
Per share, diluted	0.03	0.27	0.12	0.30	0.36	0.61	0.13	0.45
Capital investment	681,871	500,223	406,526	341,840	371,094	319,897	243,226	209,627
Cash and short-term investments	1,803,338	2,007,841	1,607,036	1,111,150	1,402,390	1,647,069	1,831,937	1,926,429
Working capital	1,298,955	1,655,915	1,307,325	902,424	1,183,628	1,475,245	1,619,557	1,806,881
Long-term debt	2,823,207	2,488,609	2,461,676	1,751,552	1,718,474	1,751,539	1,791,695	1,660,445
Shareholders' equity	4,817,253	4,870,534	4,092,556	4,027,652	4,049,633	3,984,104	3,879,415	3,983,825
BUSINESS ENVIRONMENT								
West Texas Intermediate (WTI) US$/bbl	94.37	88.18	92.22	93.49	102.92	94.06	89.76	102.56
C$ equivalent of 1US$ - average	1.0089	0.9913	0.9948	1.0102	1.0012	1.0231	0.9802	0.9676
Differential – WTI vs blend ($/bbl)	39.96	26.13	29.54	29.83	32.10	17.47	23.53	22.88
Differential – WTI vs blend (%)	41.9%	29.9%	32.2%	31.6%	31.2%	18.2%	26.7%	23.1%
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bpd	32,531	32,292	23,941	30,429	28,446	30,032	20,945	27,826
Diluent usage – bpd	16.239	14,810	9,466	13,800	13,919	14,223	8,229	12,647
Blend sales – bpd	48,632	47,532	33,342	44,029	42,486	44,491	28,820	40,507
Blend sales	55.24	61.29	62.19	64.62	70.95	78.76	64.46	76.37
Cost of diluent	(25.20)	(15.62)	(15.70)	(19.03)	(20.80)	(10.77)	(12.67)	(13.59)
Bitumen realization	30.04	45.67	46.49	45.59	50.15	67.99	51.79	62.78
Transportation – net	(0.12)	(0.05)	(0.93)	(0.03)	(0.37)	(1.19)	(1.93)	(1.18)
Royalties	(1.58)	(2.23)	(2.10)	(2.84)	(2.63)	(3.66)	(2.82)	(3.69)
Operating costs – non-energy	(8.81)	(8.70)	(15.23)	(7.79)	(8.24)	(8.55)	(17.20)	(8.74)
Operating costs – energy	(4.93)	(4.65)	(3.22)	(2.62)	(3.18)	(4.61)	(5.05)	(5.39)
Power sales	3.30	4.40	2.84	1.86	3.47	4.66	5.13	2.77
Cash operating netback	**17.90**	**34.44**	**27.85**	**34.17**	**39.20**	**54.64**	**29.92**	**46.55**
Power sales price (C$/MWh)	59.92	79.62	57.99	36.85	58.25	78.91	93.33	46.95
Power sales (MW/h)	74	75	49	64	71	74	47	68
Depletion and depreciation rate	15.16	14.98	13.39	13.01	13.44	12.60	12.51	12.37
COMMON SHARES								
Shares outstanding, end of period (000)	221,256	220,190	195,248	194,326	193,986	193,472	192,978	192,767
Volume traded (000)	28,495	20,370	13,578	21,560	18,230	16,083	16,706	34,428
Common share price ($)								
High	35.67	38.74	41.90	43.96	47.11	48.48	52.90	52.68
Low	30.89	30.25	35.20	32.92	36.73	32.26	36.96	46.25
Close (end of period)	32.61	30.44	37.39	36.49	38.46	41.57	38.76	50.32

Interim Financial Statements

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

As at	Note	March 31, 2013	December 31, 2012
Assets			
Current assets			
Cash and cash equivalents	18	**$ 1,684,810**	$ 1,474,843
Short-term investments		**118,528**	532,998
Trade receivables and other	6	**131,799**	110,823
Inventories		**20,832**	17,536
		1,955,969	2,136,200
Non-current assets			
Property, plant and equipment	7	**5,895,749**	5,267,885
Exploration and evaluation assets	8	**557,165**	554,349
Other intangible assets	9	**52,809**	46,033
Other assets	10	**13,659**	14,212
Total assets		**$ 8,475,351**	$ 8,018,679
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	11	**$ 631,310**	$ 463,077
Current portion of long-term debt	12	**13,203**	9,949
Current portion of provisions and other liabilities	13	**12,501**	7,259
		657,014	480,285
Non-current liabilities			
Long-term debt	12	**2,810,004**	2,478,660
Provisions and other liabilities	13	**131,527**	117,756
Deferred income tax liability		**59,553**	71,444
Total liabilities		**3,658,098**	3,148,145
Commitments and contingencies	20		
Shareholders' equity			
Share capital	14	**4,706,436**	4,694,378
Contributed surplus	14	**108,122**	102,219
Retained earnings		**2,618**	73,912
Accumulated other comprehensive income		**77**	25
Total shareholders' equity		**4,817,253**	4,870,534
Total liabilities and shareholders' equity		**$ 8,475,351**	$ 8,018,679

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

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

			Three months ended March 31		
	Note		**2013**		2012
Petroleum revenue, net of royalties	15	**$**	**242,976**	$	267,461
Other revenue	16		**14,993**		12,114
			257,969		279,575
Diluent and transportation			**159,948**		147,957
Purchased product and storage			**6,011**		-
Operating expenses			**40,041**		29,682
Depletion and depreciation	7, 9		**44,415**		34,786
General and administrative			**22,767**		14,731
Stock-based compensation	14		**6,955**		5,334
Research and development			**1,283**		1,294
			281,420		233,784
Revenues less operating expenses			**(23,451)**		45,791
Other income (expense)					
Interest and other income			**5,271**		5,549
Gain on disposition of asset			**-**		3,075
Foreign exchange gain (loss), net			**(42,145)**		28,601
Net finance expense	17		**(22,962)**		(20,474)
			(59,836)		16,751
Income (loss) before income taxes			**(83,287)**		62,542
Deferred income tax recovery (expense)			**11,993**		(9,173)
Net income (loss)			**(71,294)**		53,369
Other comprehensive income					
Foreign currency translation adjustment			**52**		-
Comprehensive income (loss) for the period		**$**	**(71,242)**	$	53,369
Earnings (loss) per share					
Basic	19	**$**	**(0.32)**	$	0.28
Diluted	19	**$**	**(0.32)**	$	0.27

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

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

	Note	Share Capital	Contributed Surplus	Retained Earnings	Accumulated Other Comprehensive Income (AOCI)	Total Shareholders' Equity
Balance at January 1, 2013		**$ 4,694,378**	**$ 102,219**	**$ 73,912**	**$ 25**	**$ 4,870,534**
Share issue costs, net of tax		**332**				**332**
Stock options exercised	14	**11,726**	**(2,711)**			**9,015**
Stock-based compensation	14		**8,614**			**8,614**
Net loss				**(71,294)**		**(71,294)**
Other comprehensive income					**52**	**52**
Balance at March 31, 2013		**$ 4,706,436**	**$ 108,122**	**$ 2,618**	**$ 77**	**$ 4,817,253**
Balance at January 1, 2012		$ 3,877,193	$ 85,568	$ 21,343	$ -	$ 3,984,104
Stock options exercised		6,854	(1,514)			5,340
Stock-based compensation			6,820			6,820
Net income				53,369		53,369
Balance at March 31, 2012		$ 3,884,047	$ 90,874	$ 74,712	$ -	$ 4,049,633

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

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

		Three months ended March 31	
	Note	**2013**	2012
Cash provided by (used in):			
Operating activities			
Net income (loss)		$ **(71,294)**	$ 53,369
Adjustments for:			
Depletion and depreciation		**44,415**	34,786
Stock-based compensation		**6,955**	5,334
Unrealized loss (gain) on foreign exchange		**40,917**	(28,234)
Unrealized (gain) on derivative financial liabilities	13	**(4,304)**	(1,126)
Deferred income tax (recovery) expense		**(11,993)**	9,173
Other		**2,375**	(1,311)
Net change in non-cash operating working capital items	18	**(32,063)**	(30,433)
Net cash (used in) provided by operating activities		**(24,992)**	41,558
Investing activities			
Capital investments		**(668,932)**	(364,862)
Proceeds on disposition of assets		**-**	7,456
Other		**(1,888)**	(152)
Net change in non-cash investing working capital items	18	**590,494**	185,930
Net cash used in investing activities		**(80,326)**	(171,628)
Financing activities			
Issue of shares		**9,457**	5,340
Issue of long-term debt		**307,950**	-
Repayment of long-term debt		**(3,301)**	(2,498)
Financing costs		**(7,160)**	(5,953)
Net cash provided by (used in) financing activities		**306,946**	(3,111)
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**8,339**	(3,046)
Change in cash and cash equivalents		**209,967**	(136,227)
Cash and cash equivalents, beginning of period		**1,474,843**	1,495,131
Cash and cash equivalents, end of period		$ **1,684,810**	$ 1,358,904

The accompanying notes are an integral part of these condensed 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 sections of oil sands leases in the Athabasca oil sands region of northern Alberta and is primarily engaged in a steam assisted gravity drainage oil sands development at its 80 section Christina Lake Regional Project ("Christina Lake project"). The Corporation is using a staged approach to development. The development also includes co-ownership of 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. The Corporation's 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 financial statements for the year ended December 31, 2012, except as described in Note 3 below. 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 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 financial statements for the year ended December 31, 2012. These interim consolidated financial statements should be read in conjunction with the Corporation's audited financial statements for the year ended December 31, 2012, which are included in the Corporation's 2012 annual report. The accompanying interim consolidated financial statements include all adjustments, composed of normal recurring adjustments, considered necessary by management to fairly state the Corporation's results of operations, financial position and cash flows. The operating results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the full year.

3. CHANGE IN ACCOUNTING POLICIES

The Corporation has adopted the following new and revised standards, along with all consequential amendments, effective January 1, 2013. These changes are made in accordance with the applicable transitional provisions.

IFRS 10, Consolidated Financial Statements, replaces the guidance on control and consolidation in IAS 27, Consolidated and Separate Financial Statements, and SIC-12, Consolidation – Special Purpose Entities. IFRS 10 requires consolidation of an investee only if the investor possesses power over the investee, has exposure to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect its returns. Detailed guidance is provided on applying the definition of control. The accounting requirements for consolidation have remained largely consistent with IAS 27. The Corporation assessed its consolidation conclusions on January 1, 2013 and determined that the adoption of IFRS 10 did not result in any change in the consolidation status of its wholly-owned subsidiary, MEG Energy (U.S.) Inc.

IFRS 11, Joint Arrangements, supersedes IAS 31, Interests in Joint Ventures, and requires joint arrangements to be classified either as joint operations or joint ventures depending on the contractual rights and obligations of each investor that jointly controls the arrangement. For joint operations, a company recognizes its share of assets, liabilities, revenues and expenses of the joint operation. An investment in a joint venture is accounted for using the equity method as set out in IAS 28, Investments in Associates and Joint Ventures (amended in 2011). The other amendments to IAS 28 did not affect the Corporation. The Corporation classified its joint arrangements in accordance with IFRS 11 on January 1, 2013 and concluded that the adoption of the standard did not result in any changes in the accounting for its joint arrangements.

IFRS 13, Fair Value Measurement, provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. Under IFRS 13, the fair value of a liability must reflect the effect of non-performance risk, which includes an entity's own credit risk. Upon adoption of IFRS 13, the Corporation began including an estimate of its own credit risk in determining the fair value of its derivative financial liabilities. The Corporation adopted IFRS 13 and the required change in valuation techniques on January 1, 2013 on a prospective basis. Upon adoption of IFRS 13, derivative financial liabilities decreased by $1.8 million.

The Corporation has adopted the amendments to IAS 1, Presentation of Financial Statements, effective January 1, 2013. These amendments required the Corporation to group other comprehensive income items by those that will be reclassified subsequently to profit or loss and those that will not be reclassified. These changes did not result in any adjustments to other comprehensive income or comprehensive income.

The Corporation has adopted the amendments to IAS 19, Employee Benefits, effective January 1, 2013. These amendments make significant changes to the recognition and measurement of defined benefit pension expense and termination benefits and to enhance the disclosure of all employee benefits. The adoption of these amendments did not have an impact on the Corporation's consolidated financial statements.

4. PRINCIPLES OF CONSOLIDATION

The interim consolidated financial statements of the Corporation comprise the Corporation and its wholly-owned subsidiary, MEG Energy (U.S.) Inc. All intercompany transactions and balances are eliminated on consolidation.

5. FINANCIAL INSTRUMENTS AND DERIVATIVE FINANCIAL LIABILITIES

The financial instruments recognized on the balance sheet are comprised of cash and cash equivalents, short-term investments, trade receivables and other, other assets, accounts payable and accrued liabilities, derivative financial liabilities and long-term debt. As at March 31, 2013, short-term investments, other assets, 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, short-term investments, trade receivables and other, and accounts payable and accrued liabilities included on the 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 other assets, derivative financial liabilities and long-term debt

			Fair value measurements using		
As at March 31, 2013	**Carrying amount**	**Fair value**	**Quoted prices in active markets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
Recurring measurements:					
Financial assets					
Other assets	**$ 7,541**	**$ 7,541**	**$ -**	**$ -**	**$ 7,541**
Financial liabilities					
Derivative financial liabilities	**45,933**	**45,933**	**-**	**45,933**	**-**
Long-term debt	**2,878,464**	**2,975,147**	**2,975,147**	**-**	**-**

			Fair value measurements using		
As at December 31, 2012	Carrying amount	Fair value	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Recurring measurements:					
Financial assets					
Other assets	$ 7,581	$ 7,581	$ -	$ -	$ 7,581
Financial liabilities					
Derivative financial liabilities	37,195	37,195	-	37,195	-
Long-term debt	2,488,609	2,612,763	2,612,763	-	-

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

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

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

The 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.

Level 3 fair value measurements are based on unobservable information.

Other assets are comprised of investments in asset-backed commercial paper that were restructured into MAV notes and US auction rate securities ("ARS"). The Corporation estimated the fair value of the MAV notes and the ARS based on the following: (i) the underlying structure of the notes and the securities; (ii) the present value of future principal and interest payments discounted at rates considered to reflect current market conditions for similar securities; and (iii) consideration of the probabilities of default, based on the quoted credit rating for the respective notes and securities. These estimated fair values could change significantly based on future market conditions.

The Corporation recognizes transfers into and transfers out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer. There were no transfers between levels of the fair value hierarchy during the period ended March 31, 2013.

(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 fix the interest rate on US$748.0 million of the US$1.3 billion senior secured term loan. At March 31, 2013, there was an unrealized loss on the interest rate swaps of $11.2 million (December 31, 2012 - $12.4 million).

Amount	Effective date	Remaining term	Fixed rate	Floating rate
US$300 million	September 30, 2011	Apr 2013-Sept 2016	4.686%	3 month LIBOR(1)
US$150 million	December 31, 2011	Apr 2013-Sept 2016	4.626%	3 month LIBOR(1)
US$150 million	January 12, 2012	Apr 2013-Sept 2016	4.552%	3 month LIBOR(1)
US$148 million	January 27, 2012	Apr 2013-Sept 2016	4.468%	3 month LIBOR(1)

(1) *London Interbank Offered Rate*

6. TRADE RECEIVABLES AND OTHER

		March 31, 2013		December 31, 2012
Trade receivables	**$**	**120,913**	$	104,008
Deposits and advances		**8,828**		4,757
Current portion of deferred financing costs		**2,058**		2,058
	$	**131,799**	$	110,823

7. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Corporate assets	Total
Cost				
Balance as at December 31, 2011	$ 3,027,073	$ 530,684	$ 27,610	$ 3,585,367
Additions	1,300,515	262,987	5,987	1,569,489
Disposals	(6,340)	-	-	(6,340)
Transfer from exploration and evaluation assets (note 8)	478,347	-	-	478,347
Balance as at December 31, 2012	$ 4,799,595	$ 793,671	$ 33,597	$ 5,626,863
Additions	509,638	159,366	3,034	672,038
Balance as at March 31, 2013	**$ 5,309,233**	**$ 953,037**	**$ 36,631**	**$ 6,298,901**

Accumulated depletion and depreciation				
Balance as at December 31, 2011	$ 197,469	$ 15,758	$ 3,321	$ 216,548
Depletion and depreciation for the period	134,045	7,073	3,270	144,388
Disposals	(1,958)	-	-	(1,958)
Balance as at December 31, 2012	$ 329,556	$ 22,831	$ 6,591	$ 358,978
Depletion and depreciation for the period	41,119	1,997	1,058	44,174
Balance as at March 31, 2013	**$ 370,675**	**$ 24,828**	**$ 7,649**	**$ 403,152**

Carrying Amounts				
As at December 31, 2012	$ 4,470,039	$ 770,840	$ 27,006	$ 5,267,885
As at March 31, 2013	**$ 4,938,558**	**$ 928,209**	**$ 28,982**	**$ 5,895,749**

During the three months ended March 31, 2013, the Corporation capitalized $5.9 million (three months ended March 31, 2012 - $4.4 million) of general and administrative costs and $1.7 million (three months ended March 31, 2012 - $1.5 million) of stock-based compensation costs relating to oil sands exploration and development activities. In addition, $13.6 million of interest and finance charges related to the development of capital projects were capitalized during the three months ended March 31, 2013 (three months ended March 31, 2012 - $4.5 million).

8. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2011	$	991,805
Additions		40,891
Transfer to property, plant and equipment (note 7)		(478,347)
Balance as at December 31, 2012	$	554,349
Additions		2,816
Balance as at March 31, 2013	**$**	**557,165**

Exploration and evaluation assets were transferred to property, plant and equipment – crude oil assets following the determination of technical feasibility and commercial viability of the Surmont project.

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. These assets are not subject to depletion, as they are in the exploration and evaluation stage, but are reviewed on a quarterly basis for any indication of impairment. As of March 31, 2013, no impairment has been recognized on these assets.

9. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2011	$	38,186
Additions		9,303
Balance as at December 31, 2012	$	47,489
Additions		7,017
Balance as at March 31, 2013	**$**	**54,506**

Accumulated depreciation		
Balance as at December 31, 2011	$	894
Depreciation		562
Balance as at December 31, 2012	$	1,456
Depreciation		241
Balance as at March 31, 2013	**$**	**1,697**

Carrying Amounts		
As at December 31, 2012	$	46,033
As at March 31, 2013	**$**	**52,809**

Other intangible assets include the cost to maintain the right to participate in a potential pipeline project and the cost of software that is not an integral part of the related computer hardware.

10. OTHER ASSETS

		March 31, 2013		December 31, 2012
MAV Notes[(a)]	$	5,391	$	5,475
ARS[(b)]		2,150		2,106
Deferred financing costs[(c)]		8,176		8,689
		15,717		16,270
Less current portion of deferred financing costs		(2,058)		(2,058)
	$	13,659	$	14,212

(a) The Corporation's investment in MAV Notes that mature between 2016 and 2056 are classified as held-for-trading which requires them to be measured at fair value at each period end with changes in fair value included in net finance expense in the period in which they arise.

(b) The investment in ARS is considered an illiquid asset and is recorded at its fair value based on a discounted cash flow valuation using observable information with changes in fair value included in net finance expense in the period in which they arise.

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

11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

		March 31, 2013		December 31, 2012
Trade payables	$	95,172	$	51,651
Accrued liabilities		518,982		370,431
Interest payable		12,731		36,848
Other payables		4,425		4,147
	$	631,310	$	463,077

12. LONG-TERM DEBT

		March 31, 2013		December 31, 2012
Senior secured term loan (March 31, 2013 – US$1.284 billion; December 31, 2012 - US$987.5 million)[(a)]	$	1,304,284	$	982,464
6.5% senior unsecured notes (US$750 million)[(b)]		761,700		746,175
6.375% senior unsecured notes (US$800 million)[(c)]		812,480		795,920
		2,878,464		2,524,559
Less current portion of senior secured term loan		(13,203)		(9,949)
Less unamortized financial derivative liability discount		(23,002)		(10,324)
Less unamortized deferred debt issue costs		(32,255)		(25,626)
	$	2,810,004	$	2,478,660

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.0156 (December 31, 2012 - US$1 = C$0.9949).

(a) On February 25, 2013, the Corporation re-priced, increased and extended its existing US$987.5 million senior secured term loan. The Corporation extended the maturity date to March 31, 2020 and increased its borrowing under the senior secured term loan by US$300.0 million. In addition, the Corporation reduced the interest rate on the term loan by 25 basis points.

The senior secured credit facilities are comprised of a US$1.284 billion term loan and a five year US$1.0 billion revolving credit facility. The term loan bears a floating interest rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 175 or 275 basis points, respectively, and an interest rate floor of 200 basis points based on U.S. Prime or 100 basis points based on LIBOR. The term loan is to be repaid in quarterly installment payments equal to US$3.250 million beginning on March 28, 2013, with the balance due on March 31, 2020. Interest is paid quarterly. The Corporation has deferred the associated debt issue costs of $7.2 million and is amortizing these costs over the life of the loan utilizing the effective interest method.

Effective March 21, 2012, the Corporation agreed to amend, extend and increase its revolving credit facility from US$500.0 million to US$1.0 billion with a maturity date of March 21, 2017. As at March 31, 2013, $2.6 million (December 31, 2012 - $2.6 million) of the revolving credit facility was utilized to support letters of credit. As at March 31, 2013, no amount had been drawn under the revolving credit facility.

(b) Effective March 18, 2011, the Corporation issued US$750.0 million in aggregate principal amount of 6.5% Senior Unsecured Notes, with a maturity date of March 15, 2021. Interest is paid semi-annually on March 15 and September 15. No principal payments are required until March 15, 2021. The Corporation has deferred the associated remaining debt issue costs of $12.1 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

(c) Effective July 19, 2012, the Corporation issued US$800.0 million in aggregate principal amount of 6.375% Senior Unsecured Notes, with a maturity date of January 30, 2023. Interest is paid semi-annually on January 30 and July 30. No principal payments are required until January 30, 2023. The Corporation has deferred the associated remaining debt issue costs of $13.0 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

13. PROVISIONS AND OTHER LIABILITIES

		March 31, 2013		December 31, 2012
Derivative financial liabilities[(a)]	**$**	**45,933**	$	37,195
Decommissioning provision[(b)]		**92,516**		82,087
Deferred lease inducements[(c)]		**5,579**		5,733
Provisions and other liabilities		**144,028**		125,015
Less current portion of derivative financial liabilities		**(8,438)**		(6,509)
Less current portion of decommissioning provision		**(3,444)**		-
Less current portion of deferred lease inducements		**(619)**		(750)
Non-current portion of provisions and other liabilities	**$**	**131,527**	$	117,756

(a) Derivative financial liabilities

		March 31, 2013		December 31, 2012
1% interest rate floor	$	**34,774**	$	24,807
Interest rate swaps		**11,159**		12,388
Derivative financial liabilities		**45,933**		37,195
Less current portion of derivative financial liabilities		**(8,438)**		(6,509)
Non-current portion of derivative financial liabilities	$	**37,495**	$	30,686

The interest rate floor on the senior secured term loan has been recognized as an embedded derivative as the floor rate exceeded the market rate of interest at the time that the debt was incurred. As a result, the interest rate floor derivative is required to be separated from the carrying value of long-term debt and accounted for as a separate derivative financial liability measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

The Corporation is exposed to interest rate risk in relation to interest income earned on cash and cash equivalents and short-term investments and in relation to interest expense on floating rate long-term debt. To mitigate a portion of the risk of interest rate increases on long-term debt, the Corporation periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. As of March 31, 2013, the Corporation had entered into interest rate swaps on US$748.0 million (note 5(b)) and these interest rate swap contracts expire on September 30, 2016. Interest rate swaps are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

(b) The following table presents the decommissioning provision associated with the reclamation and abandonment of crude oil properties:

		March 31, 2013		December 31, 2012
Decommissioning provision, beginning of period	$	**82,087**	$	65,360
Changes in estimated future cash flows		**847**		-
Changes in discount rates		**5,821**		(3,846)
Liabilities incurred		**4,612**		18,218
Liabilities settled		**(1,927)**		(1,315)
Accretion		**1,076**		3,670
Decommissioning provision, end of period		**92,516**		82,087
Less current portion of decommissioning provision		**(3,444)**		-
Non-current portion of decommissioning provision	$	**89,072**	$	82,087

The total decommissioning provision is based on the estimated costs to reclaim and abandon the Corporation's crude oil properties and the estimated timing of the costs to be incurred in future years. The Corporation has estimated the net present value of the decommissioning obligations to be $92.5 million as at March 31, 2013 (December 31, 2012 - $82.1 million) based on an undiscounted total future liability of $235.7 million (December 31, 2012 - $228.1 million) and a credit-adjusted rate of 5.3% (December 31, 2012 – 5.7%). This obligation is estimated to be settled in periods up to 2057.

(c) Leasehold inducements were received when the Corporation entered into the corporate office lease. These inducements are recognized as a deferred liability and amortized over the life of the lease.

14. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

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

	Three months ended March 31, 2013			Year ended December 31, 2012	
	Number of shares		**Amount**	Number of shares	Amount
Balance, beginning of period	**220,190,084**	**$**	**4,694,378**	193,471,705	$ 3,877,193
Shares issued	**-**		**-**	24,246,212	800,125
Share issue costs, net of tax	**-**		**332**	-	(18,988)
Issued upon exercise of stock options	**1,066,317**		**11,726**	2,243,319	26,520
Issued upon vesting and release of RSUs	**-**		**-**	228,848	9,528
Balance, end of period	**221,256,401**	**$**	**4,706,436**	220,190,084	$ 4,694,378

On December 28, 2012, the Corporation issued 24,246,212 common shares at a price of $33.00 per share for gross proceeds of $800.1 million.

(c) Stock options outstanding:

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

	Three months ended March 31, 2013			Year ended December 31, 2012		
	Stock options		**Weighted average exercise price per share**	Stock options		Weighted average exercise price per share
Outstanding, beginning of period	**9,147,404**	**$**	**32.50**	10,190,103	$	27.12
Granted	**32,228**		**33.40**	1,456,537		35.67
Exercised	**(1,066,317)**		**8.45**	(2,243,319)		9.21
Forfeited	**(45,216)**		**40.85**	(255,917)		40.29
Outstanding, end of period	**8,068,099**	**$**	**35.63**	9,147,404	$	32.50

(d) Restricted share units outstanding:

The RSU Plan allows for the granting of Restricted Share Units ("RSUs") to directors, officers, employees and consultants of the Corporation. An RSU represents the right for the holder to receive a cash payment (subject to the consent of the Corporation and its Board of Directors) or its equivalent in fully-paid common shares equal to the fair market value of the Corporation's common shares calculated at the date of such payment. RSUs granted under the RSU Plan generally vest annually over a three year period.

	Three months ended March 31, 2013	Year ended December 31, 2012
	RSUs	RSUs
Outstanding, beginning of period	**953,804**	554,362
Granted	**-**	664,796
Vested and released	**-**	(228,848)
Forfeited	**(7,125)**	(36,506)
Outstanding, end of period	**946,679**	953,804

(e) Contributed Surplus:

	Three months ended March 31, 2013	Year ended December 31, 2012
Balance, beginning of period	**$ 102,219**	$ 85,568
Stock-based compensation - expensed	**6,955**	25,246
Stock-based compensation - capitalized	**1,659**	6,796
Stock options exercised	**(2,711)**	(5,863)
RSUs vested and released	-	(9,528)
Balance, end of period	**$ 108,122**	$ 102,219

15. PETROLEUM REVENUE

	Three months ended March 31	
	2013	2012
Petroleum sales:		
Proprietary	$ 241,800	$ 274,295
Third party	5,778	-
	247,578	274,295
Royalties	(4,602)	(6,834)
Petroleum revenue	$ 242,976	$ 267,461

16. OTHER REVENUE

	Three months ended March 31	
	2013	2012
Power revenue	**$ 9,616**	$ 9,026
Transportation revenue	**5,377**	3,088
Other revenue	**$ 14,993**	$ 12,114

17. NET FINANCE EXPENSE

	Three months ended March 31	
	2013	2012
Total interest expense	**$ 38,723**	$ 24,250
Less capitalized interest	**(13,634)**	(4,543)
Net interest expense	**25,089**	19,707
Accretion on decommissioning provision	**1,076**	833
Unrealized fair value (gain) on embedded derivative liabilities	**(3,075)**	(2,458)
Unrealized fair value (gain) loss on interest rate swaps	**(1,229)**	1,332
Realized loss on interest rate swaps	**1,101**	1,060
Net finance expense	**$ 22,962**	$ 20,474

18. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended March 31	
	2013	2012
Changes in non-cash working capital		
Operating activities:		
Trade receivables and other	**$ (22,005)**	$ 25,773
Inventories	**(3,296)**	(9,049)
Accounts payable and accrued liabilities	**(6,762)**	(47,157)
Change in operating non-cash working capital	**$ (32,063)**	$ (30,433)
Investing activities:		
Short-term investments	**$ 414,469**	$ 108,452
Accounts payable and accrued liabilities	**176,025**	77,478
Change in investing non-cash working capital	**$ 590,494**	$ 185,930
Change in total non-cash working capital	**$ 558,431**	$ 155,497
Cash and cash equivalents:		
Cash	**$ 348,328**	$ 35,871
Cash equivalents	**1,336,482**	1,323,033
	$ 1,684,810	$ 1,358,904

19. EARNINGS PER COMMON SHARE

	Three months ended March 31	
	2013	2012
Net income (loss)	**$ (71,294)**	$ 53,369
Weighted average common shares outstanding	**221,046,678**	193,886,405
Dilutive effect of stock options and restricted share units	**1,700,746**	4,062,934
Weighted average common shares outstanding – diluted	**222,747,424**	197,949,339
Earnings (loss) per share, basic	**$ (0.32)**	$ 0.28
Earnings (loss) per share, diluted	**$ (0.32)**	$ 0.27

20. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at March 31, 2013:

Operating:

	2013	2014	2015	2016	2017	Thereafter
Office lease rentals	$ 8,237	$ 10,982	$ 11,155	$ 11,550	$ 29,234	$ 334,362
Diluent purchases	315,198	56,092	-	-	-	-
Pipeline transportation	750	31,546	31,046	62,261	62,091	1,242,846
Other commitments	23,743	36,705	19,970	6,968	6,414	36,531
Annual commitments	$ 347,928	$ 135,325	$ 62,171	$ 80,779	$ 97,739	$ 1,613,739

Capital:

As part of normal operations, the Corporation has entered into a total of $822.2 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.

21. COMPARATIVE FIGURES

Certain of the comparative figures have been reclassified to conform to the presentation adopted in the current year.