MEG Energy

RAISING THE BAR

ANNUAL REPORT 2012

A Pure Play Oil Sands Investment.
MEG Energy Corp. is a Canadian energy company focused on sustainable in situ development and production in the southern Athabasca oil sands region of Alberta. With a large resource base, efficient technologies and an innovative marketing strategy, MEG is positioned to build on our past success and raise the bar on our performance for years to come.

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Operational and **Financial Highlights**

($ per barrel unless specified)	2012 Quarterly Performance Q1	Q2	Q3	Q4	Full Year 2012	2011
Bitumen production – barrels per day	28,446	30,429	23,941	32,292	**28,773**	**26,605**
Steam-oil ratio	2.5	2.4	2.5	2.4	**2.4**	**2.4**
West Texas Intermediate (WTI) US$ / barrel	102.92	93.49	92.22	88.18	**94.21**	**95.12**
Differential – WTI / blend %	31.2%	31.6%	32.2%	29.9%	**31.2%**	**23.5%**
Bitumen realization	50.15	45.59	46.49	45.67	**46.93**	**58.74**
Transportation	(0.37)	(0.03)	(0.93)	(0.05)	**(0.31)**	**(1.39)**
Royalties	(2.63)	(2.84)	(2.10)	(2.23)	**(2.46)**	**(3.24)**
Net bitumen revenue	47.15	42.72	43.46	43.39	**44.16**	**54.11**
Energy costs	(3.18)	(2.62)	(3.22)	(4.65)	**(3.46)**	**(5.14)**
Non-energy costs	(8.24)	(7.79)	(15.23)	(8.70)	**(9.71)**	**(10.32)**
Power sales	3.47	1.86	2.84	4.40	**3.19**	**4.50**
Net operating costs	(7.95)	(8.55)	(15.61)	(8.95)	**(9.98)**	**(10.96)**
Cash operating netback [1]	39.20	34.17	27.85	34.44	**34.18**	**43.15**
Net income (loss) - $millions	53.4	(29.5)	47.5	(18.7)	**52.6**	**63.8**
Per share, diluted	0.27	(0.15)	0.24	(0.09)	**0.26**	**0.32**
Operating earnings (loss) - $millions [2]	23.5	11.1	(12.9)	(0.5)	**21.2**	**109.3**
Per share, diluted	0.12	0.06	(0.07)	0.00	**0.11**	**0.55**
Cash flow from operations - $millions [2]	72.0	60.0	24.4	56.1	**212.5**	**304.6**
Per share, diluted	0.36	0.30	0.12	0.27	**1.06**	**1.54**
Cash and short-term investments - $millions	1,402.4	1,111.2	1,607.0	2,007.8	**2,007.8**	**1,647.1**
Long-term debt - $millions	1,718.5	1,751.6	2,461.7	2,488.6	**2,488.6**	**1,751.5**
Capital cash investment - $millions	364.9	339.1	399.7	494.9	**1,598.5**	**928.9**

[1] Cash operating netbacks are calculated by deducting the related royalties and 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 Netback analysis within the "Results of Operations" section in the attached Management's Discussed and Analysis ("MD&A").

[2] 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 and investors 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 operating activities in accordance with IFRS under the heading "Non-IFRS Measurements" in the attached MD&A.

Message to **Shareholders**

From MEG's earliest days of meeting at improvised boardroom tables to hiking though muskeg on exploration ventures, **we have worked to build on a sole focus of creating a unique and innovative energy business** that finds the right balance between blue-sky inspiration and the boots-on-the-ground experience of a veteran team.

Our efforts have demonstrated success on delivering strong operational performance, while laying the groundwork for a new era in our ongoing strategy. Our results in 2012 cap another successful chapter in the MEG story with increases to reserves, record-high production volumes, record-low operating costs and major milestones achieved along the path to our goal of reaching production capacity of 260,000 barrels per day by the end of the decade.

The growing strength of our strategic foundation over the past several years positions MEG for what we see as a truly transformational year in 2013 – a year in which we will raise the bar still further as we embark on a new phase of production growth and building sustainable shareholder value.

"How we develop our large reserves is as **important as the size of the resource base itself.**"

Foundation for the future

While many of our successes in 2012 are apparent from our operational and financial figures, some of our biggest successes have been "below the surface" and will begin to emerge more fully in 2013. In fact, our growing proven reserves and the innovative technologies being deployed to develop those reserves are quite literally *below the surface* and combine to form a foundation for what we believe will be a step-change in value creation.

That foundation starts with MEG's high-quality resource base, covering over 2,300 square kilometres of leases in which we hold a 100% working interest. Our current focus is in the Christina Lake region, which has been established by both MEG's operations and those of our competitors as one of the premium plays in the Athabasca oil sands.

In 2012, we received regulatory approval for our next, multi-stage development – Christina Lake Phase 3. We now have critical approvals and facility plans in hand for production of 210,000 barrels per day. With the addition of our regulatory submission for MEG's Surmont Project and plans to begin construction of the first phase in 2016, we are poised to increase our production capacity further still toward our goal of 260,000 barrels per day by 2020. As the pieces move into place to execute our growth plan, regulatory and resource certainty have helped increase MEG's year-over-year proved-plus-probable reserves by more than 25% to 2.6 billion barrels at the end of 2012. This places MEG as one of the top five in reported oil reserves among Canadian companies.

Higher production at lower cost: the RISER initiative

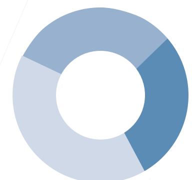
How we develop our large reserves is as important as the size of the resource base itself. After a full year of successfully demonstrating a new and innovative approach to in situ oil sands development – and following an extensive regulatory review – MEG is set to expand its RISER initiative in 2013.

The RISER initiative employs proven technologies, in combination with proprietary reservoir practices, to significantly lower steam-oil ratios. This allows us to reduce the energy cost for production from existing assets, while redeploying built-in steam capacity to new production assets. As MEG looks to take the initiative across our operations, we anticipate several benefits.

First, we are targeting higher production, earlier than previously planned. Our combined Phase 1, 2, and 2B developments were designed with a production capacity of 60,000 barrels per day. With the RISER initiative, we are now targeting production volumes of 80,000 barrels per day in early 2015 – about 30% above our original plan. That increase in production is expected to flow directly to the bottom line.

The second key benefit of RISER is its relatively low capital cost. Although RISER requires some additional investment in both drilling and minor modifications to our processing facilities, we anticipate being able to move higher volumes through our existing facilities. Our current estimates, benchmarked against third-party research, suggest that RISER will drive a supply cost for future growth that is roughly half the average supply cost for North American oil sands and unconventional oil plays. This places RISER

Resource Base*



Proven Reserves	**1.28** BILLION BARRELS
Probable Reserves	**1.36** BILLION BARRELS
Contingent Resources	**3.42** BILLION BARRELS

*Estimates of MEG's reserves and contingent resources are based upon a report prepared by GLJ Petroleum Consultants Ltd., effective December 31, 2012. Contingent resources are best estimate. There is no certainty that it will be commercially viable to produce any of the contingent resources. Statements relating to reserves and contingent resources estimates and certain other statements in this annual report relating to MEG's development plans, 2013 goals and expectations constitute forward-looking information. For further information and important advisories regarding forward-looking information and MEG's reserves and resources please refer to MEG's annual information form dated February 27, 2013.

Leveraging technology

RISER is targeted at enhancing reservoir and plant efficiencies through the wide deployment of a technology called Enhanced and Modified Steam and Gas Push, or "eMSAGP".

The technology uses non-condensable gas as a partial substitute for steam to pressurize the reservoir, together with infill wells that run between existing well pairs to reach ready-to-produce, heated bitumen. These proven technologies, in combination with proprietary reservoir practices, significantly lower steam-oil ratios (SORs), reducing energy costs and related emissions. With an SOR at our pilot well pattern of approximately 1.4, we are seeing performance that is twice as efficient as the industry average.

barrels at the lowest supply cost in our asset development portfolio and supports a total supply cost that compares favourably to the North American average for all crude oil production sectors.

The final key benefit of RISER is that it enables what we call interphase production growth. Typically, oil sands production profiles change in large defined steps as new projects are commissioned. With RISER, we plan to incrementally increase production as we drill new well pads and patterns and tie them into our production facilities. That means that over the next few years – before we realize new production from Christina Lake Phase 3A – we are targeting interphase growth at an average of 10% to 15% per year.

Improving market access: taking a leadership position in 2013

The second key way in which we are driving value is through our Hub and Spoke marketing strategy, which is focused on increasing the margins we receive for every barrel we produce. It's a plan that we have been developing since our first barrels moved through MEG's jointly-owned Access Pipeline to the Edmonton-area transportation Hub, effectively placing our well-head at the nexus of market connections for Western Canadian crude oil. The Access Pipeline is a key strategic asset that provides control over the transportation of our barrels at relatively low cost and sets the stage for further extending our ability to directly market our production and realize higher margins.

In 2013, we will raise the bar on our marketing strategy with plans to take increasing volumes beyond Edmonton directly to high-value markets, bypassing congested pipelines that have depressed heavy oil prices for Alberta production.

The launch point for these plans is MEG's 900,000 barrel capacity Stonefell Terminal, which is targeted for completion mid-year. Connected to the Access Pipeline, Stonefell will act as a clearing point to move bitumen blends and to purchase diluents when prices are favourable, providing a cushion against short-term market fluctuations. This is expected to improve both operating costs and realized prices.

Just as importantly, Stonefell will serve as our proprietary hub for moving large product batches to high-value markets. Existing pipeline spokes from Stonefell provide connections to markets from the Rocky Mountain region and West Coast to the Great Lakes and U.S. Midwest. Stonefell also sits at the centre of proposed pipeline projects targeting increased West Coast access and new connections to the U.S. Gulf Coast, which should help bring the pricing of Western Canadian production closer to international benchmarks.

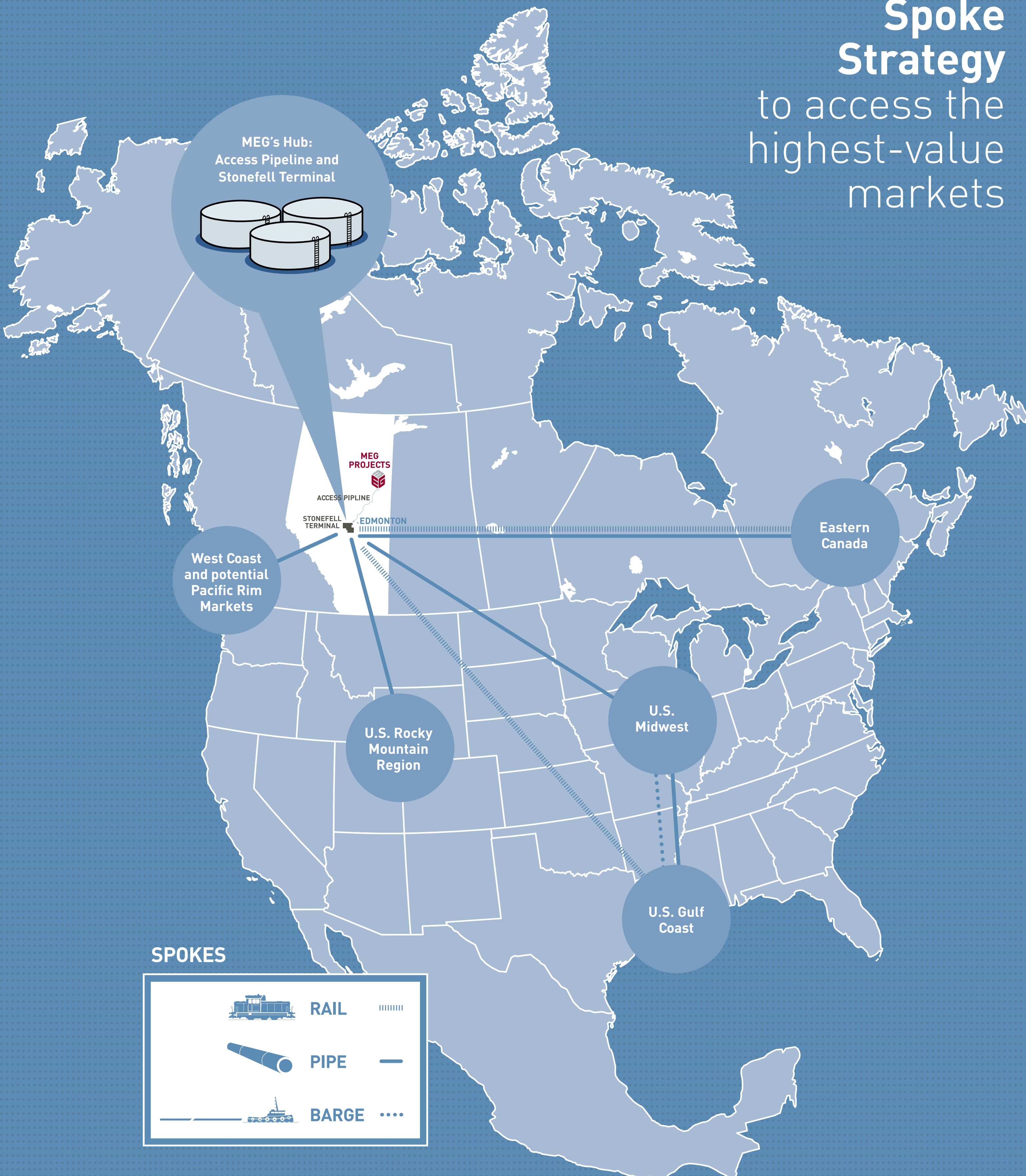
These initiatives – including the Flanagan-Seaway pipeline to the Gulf Coast on which MEG will begin shipping in 2014 – are well underway, along with many other fundamental changes in the continental energy transportation system.

While we expect longer-term benefits from improved infrastructure across the board, our strategy is focused on moving MEG ahead of the broader industry price curve in the near-term with the addition of two new market spokes.

First, we have reached an agreement to connect Stonefell to a nearby railcar-loading facility. This will provide the option to connect our barrels to nearly every refining region on the continent. In addition to rail, we have also secured barge capacity that links us to the U.S. Inland Waterway system and refineries from the mid-continent all the way to the world's largest refining complex on the Gulf of Mexico.

The benefit of these new market spokes will emerge this year as we begin to ramp up carrying capacity, allowing MEG to bypass current pipeline congestion and discounted pricing and moving us toward Mayan heavy crude pricing, which currently trades close to – or above – West Texas Intermediate benchmarks. This represents a significant advantage. Every barrel that we can move around constrained markets represents an opportunity for significantly higher netbacks, and we expect the number of barrels moving to these high-value markets to increase on a quarter-by-quarter basis beginning this summer.

Hub and Spoke Strategy to access the highest-value markets



Putting it all together: MEG's value proposition

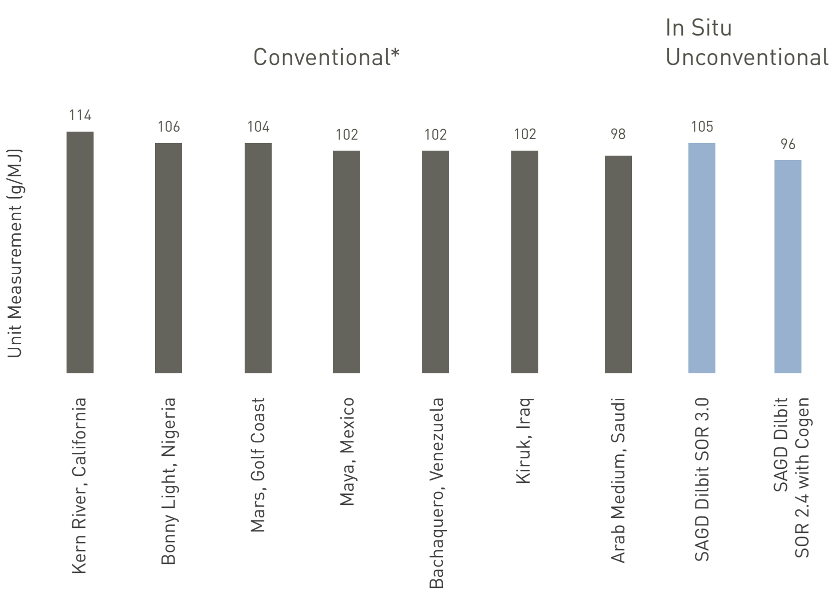
Taken together, these strategic levers – further lowering costs while increasing realized value – form the value proposition that we expect to propel MEG through our new era of growth.

We believe the best defence against volatility in commodity prices and light-heavy crude oil differentials is our strong focus and demonstrated performance on keeping our costs low. With the ongoing implementation of the RISER initiative, we expect to further solidify and improve MEG's low-cost position, with average non-energy operating costs targeted at $9 to $11 per barrel in 2013, and expected to be even lower going forward as we continue the roll-out of RISER.

Matching our focus on the cost side of the equation is our focus on the price side – the value received for every barrel we produce. With our Hub and Spoke strategy set for significant advancements in 2013, MEG is well-positioned to increase the margin between cost and price, which translates into accelerated cash flow and enhanced shareholder value on a long-term, sustainable basis. As we go forward, this equation should help close the gap between cash flow and growth capital investment requirements, moving us toward a self-funding financial structure.

As we continue to close that gap, our plans are well-funded. Debt and equity financings completed in 2012 have strengthened our balance sheet to carry us through the roll-out of RISER to Christina Lake Phases 1 and 2 to achieve our target of 80,000 barrels per day and the resulting expected increase in cash flows.

Comparing crudes: wells to wheels



MEG's production using SAGD with cogeneration has **a smaller carbon footprint than many conventional oil** sources in the North American market.

***Source** Jacobs Consultancy, "Life Cycle Assessment of North America and Imported Crudes" July 2009

“MEG’s approach to building sustainable **shareholder value is mirrored in our approach to sustainable resource development”**

A sustainable advantage

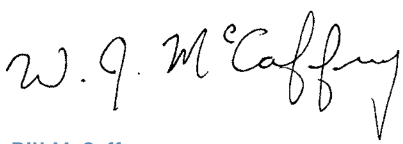
MEG’s broad and long-term approach to building sustainable shareholder value is mirrored in our approach to sustainable resource development: providing economic and social benefits while carefully managing environmental impacts. This is yet another area where our approach to continuous improvement is raising the bar on our performance.

The carbon intensity of MEG’s production is currently among the lowest in the oil sands industry and compares favourably to many sources of both North American and imported oil supplies. With the demonstrated efficiency of our operations, supported by cogeneration of steam and electricity and deployment of advanced reservoir technologies, we expect to continue to be a leader in helping to responsibly meet the energy demands of growing global economies.

The RISER initiative, as well as being cost-effective, is expected to play a key role in our focus on continuous improvement by reducing both energy and water use intensity, while driving a resource recovery-to-land disturbance ratio that is among the best in the oil and gas industry, globally.

On behalf of your Board of Directors and all MEG employees, I thank you for your support as we continue our efforts to build on our past successes and to raise the bar still further as we go forward.

Sincerely,



Bill McCaffrey

President and CEO

From left: Don Sutherland, VP Regulatory and Community Relations; Don Moe, VP, Supply and Marketing; John Rogers, VP Investor Relations and External Communications; Dale Hohm, Chief Financial Officer; Richard Sendall, Senior VP Strategy and Government Relations; Ted Semadeni, General Counsel; Bill McCaffrey, President and Chief Executive Officer; Grant Boyd, Senior VP Resource Management – Growth Properties; Jamey Fitzgibbon, Senior VP Resource Management – Christina Lake and Special Projects; Chi-Tak Yee, Senior VP Reservoir and Geosciences; Chris Sloof, VP Projects; Stephen Diotte, VP, Human Resources, IT and Corporate Services.

Proven **Performance**

2012 Our Goals and Results

Goal **ONE**

Achieve average annual production capacity of 26,000 to 28,000 barrels per day at a non-energy operating cost of $10 to $12 per barrel.

Production in 2012 averaged 28,733 barrels per day, exceeding the high-end of our target and supporting better than target non-energy operating costs of $9.71 per barrel.

Goal **TWO**

Maximize productivity and reliability of existing plants.

Current operations at Christina Lake performed above design capacity, reaching peak volumes exceeding 36,000 barrels per day. During planned maintenance in September, tests were conducted to evaluate the ability of the plant to achieve routine operations at similar or higher volumes. Outside of the September maintenance period, plant availability stood at 97.5%.

Goal **THREE**

Advance Phase 2B toward target completion in 2013 and advance development strategy and engineering work for Phase 3.

All major equipment was delivered to the Phase 2B project site with construction continuing toward planned completion in 2013. An optimized 41,000 barrel per day base-level production design was unveiled for each sub-stage of Phase 3 and the Surmont project, providing greater project development certainty and economies of scale going forward.

Goal **FOUR**

Submit regulatory application for development of the Surmont Project.

A regulatory application for a multi-phase, 120,000 barrel per day capacity project was submitted for Surmont, with construction targeted to begin in 2016.

Goal **FIVE**

Advance MEG's Hub and Spoke marketing strategy.

Additional pumping capacity was added to the jointly-owned Access pipeline, connecting MEG's producing assets to the Edmonton-area hub. Construction continued on schedule for MEG's proprietary 900,000 barrel Stonefell Terminal.

Raising **the Bar**

2013 Our Goals and Plans to Reach Them

Goal **ONE**

Achieve average annual production of 32,000 to 35,000 barrels per day at a non-energy operating cost of $9 to $11 per barrel.

Increased year-over-year production guidance and correspondingly lower non-energy operating costs reflect continuing improvements in plant efficiency and early incremental volumes from Phase 2B.

Goal **TWO**

Maximize productivity and reliability of existing plants.

Regulatory approval for expanded deployment of eMSAGP technology to new well pads and debottlenecking work are expected to deliver strong, reliable production for the full year.

Goal **THREE**

Complete construction, commissioning and start-up of Christina Lake Phase 2B.

All major equipment for Phase 2B is on site with construction ongoing. Phase 2B operations are expected to begin steam injection late in the third quarter with the plant targeted to be fully operational in the fourth quarter of 2013.

Goal **FOUR**

Advance development strategy and engineering for Christina Lake Phase 3 and Surmont projects.

Engineering and development work to optimize and integrate standard production platforms for all phases of Christina Lake and Surmont will continue. Cost and scheduling guidance for Christina Lake Phase 3A is expected mid-year.

Goal **FIVE**

Advance MEG's Hub and Spoke strategy.

MEG's Stonefell hub is scheduled for completion for mid-year, providing a launch point for pipeline, rail and barging options to bypass pipeline congestion and reach high value markets.

MANAGEMENT'S DISCUSSION AND ANALYSIS

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FINANCIAL STATEMENTS

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the year ended December 31, 2012 is dated February 26, 2013. This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2012. All tabular amounts are stated in thousands of Canadian dollars ($ or C$) unless indicated otherwise.

Overview

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the year ended December 31, 2012 is dated February 26, 2013. This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2012. All tabular amounts are stated in thousands of Canadian dollars ($ or C$) unless indicated otherwise. 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, and have a combined initial 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. On July 16, 2012, the Corporation announced the RISER production enhancement program and now anticipates reaching a total production target from Christina Lake Phases 1, 2, and 2B of approximately 80,000 bpd by early 2015. During 2012, MEG received regulatory approvals to proceed with Phase 3 and the Corporation anticipates total design production capacity at Christina Lake of 210,000 bpd.

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% 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.

Summary Annual Information

($000, except per share amounts)	2012	2011	2010
Total revenue, net of royalties	**1,050,504**	1,036,613	730,286
Net income	**52,569**	63,837	49,558
Per share – basic	**0.27**	0.33	0.28
Per share – diluted	**0.26**	0.32	0.27
Total assets	**8,018,679**	6,201,049	5,043,265
Total non-current liabilities	**2,667,860**	1,900,369	1,019,244

Total revenues have increased primarily as a result of the increase in production from the Christina Lake project. Production has increased primarily as a result of additional SAGD well pairs and infill wells brought into production, increased steam generation capacity and increased plant operating efficiencies. The increase in production was partially offset by lower bitumen realizations in 2012.

Net income has been significantly impacted by foreign exchange gains and losses (2012 - $36.6 million gain; 2011 - $35.7 million loss; 2010 - $49.1 million gain) 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 and U.S. dollar cash and cash equivalents. Net income has also been impacted by the increase in depletion and depreciation expense (2012 - $145.0 million; 2011 - $124.3 million; 2010 - $97.9 million), the increase in general and administrative expense (2012 - $70.6 million; 2011 - $55.7 million gain; 2010 - $36.4 million), and the increase in interest expense (2012 - $91.8 million; 2011 - $73.6 million; 2010 - $51.6 million).

Total assets have increased due to capital investment in the Christina Lake project, the Access Pipeline and the Stonefell Terminal, as well as resource definition at the Surmont project and the Growth Properties.

Investment activity was partially funded by:

> the Corporation's 2010 initial public offering proceeds of $663.5 million, net of issue costs;

> the issuance of US$750.0 million in aggregate principal amount of 6.5% senior unsecured notes in March 2011;

> the issuance of US$800 million in aggregate principal amount of 6.375% senior unsecured notes in July 2012; and

> the issuance of 24.2 million common shares at a price of $33.00 per share for proceeds of $774.8 million, net of issue costs, in December 2012.

For a detailed discussion of the Corporation's investing activities, see "LIQUIDITY AND CAPITAL RESOURCES – Cash Flows – Investing Activities".

Operational and Financial Highlights

The following table summarizes selected operational and financial information of the Corporation for the years ended December 31:

	2012	2011
Bitumen production – bpd	**28,773**	26,605
Steam to oil ratio	**2.4**	2.4
West Texas Intermediate (WTI) US$/bbl	**94.21**	95.12
Differential – WTI/Blend %	**31.2%**	23.5%
Bitumen realization - $/bbl	**46.93**	58.74
Net operating costs[1] - $/bbl	**9.98**	10.96
Cash operating netback[2] - $/bbl	**34.18**	43.15
Capital cash investment - $000	**1,598,514**	928,921
Net income - $000	**52,569**	63,837
Per share, diluted	**0.26**	0.32
Operating earnings - $000[3]	**21,242**	109,255
Per share, diluted[3]	**0.11**	0.55
Cash flow from operations - $000[3]	**212,514**	304,627
Per share, diluted[3]	**1.06**	1.54
Cash and short-term investments - $000	**2,007,841**	1,647,069
Long-term debt - $000	**2,488,609**	1,751,539
Bitumen Reserves and Contingent Resources (millions of barrels, before royalties)		
Proved (1P) Reserves[4]	**1,284**	708
Probable Reserves[5]	**1,360**	1,352
Proved Plus Probable (2P) Reserves[4][5]	**2,644**	2,060
Best Estimate Contingent Resources (2C)[6][7][8]	**3,420**	3,818

[1] Net operating costs include energy and non-energy operating costs, reduced by power sales for the period. 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 and net cash provided by operating activities in accordance with IFRS under the heading "NON-IFRS MEASUREMENTS" and discussed further in the "ADVISORY" section.

[4] Proved Reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Proved Reserves are also referred to as "1P Reserves".

[5] "Probable Reserves" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Proved plus probable reserves are also referred to as "2P Reserves".

[6] "Contingent Resources" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Such contingencies include further reservoir delineation, additional facility and reservoir design work, submission of regulatory applications and the receipt of corporate approvals. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

[7] There are three categories in evaluating Contingent Resources: Low Estimate, Best Estimate and High Estimate. The resource numbers presented all refer to the Best Estimate category. Best Estimate is a classification of resources described in the Canadian Oil and Gas Evaluation (COGE) Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate. Best Estimate Contingent Resources are also referred to as "2C Resources".

[8] These volumes are the arithmetic sums of the Best Estimate Contingent Resources for Christina Lake, Surmont and the Growth Properties.

Bitumen production for 2012 averaged 28,773 bpd compared to 26,605 bpd in 2011. The increase in production results from increased steam generation capabilities in 2012 compared to 2011. There were 41 SAGD well pairs and two infill wells on production as at December 31, 2012 compared to 35 SAGD well pairs on production as at December 31, 2011. With respect to the six SAGD well pairs added during 2012, one was brought into production during the first quarter, two were added in the second quarter, one well pair was brought into production during the third quarter and two well pairs were added in the fourth quarter. The two infill wells were brought into production during the first quarter of 2012.

Bitumen realizations for 2012 were impacted by market conditions as West Texas Intermediate ("WTI") prices decreased to an average of US$94.21 per barrel compared to US$95.12 per barrel during 2011. Bitumen realizations were also impacted by higher differentials between WTI and the Corporation's blend sales. The differential between the WTI price and the Corporation's blend sales price increased to 31.2% in 2012 from 23.5% in 2011. Increases in production of both light crude oil and heavier crudes have put downward pressure on both light and heavy oil prices in the U.S. mid-continent. Pipeline congestion and refinery outages in the U.S. Midwest have added to this pressure which led to a higher discount for Canadian crude in 2012.

Net operating costs for 2012 were $9.98 per barrel, compared to $10.96 per barrel in 2011. The decrease in net operating costs was the result of:

- a reduction in energy operating costs, primarily as a result of lower natural gas prices; and
- a decline in annual non-energy operating costs on a per barrel basis, which has largely been driven by higher production volumes. Tight control over costs and efficient plant utilization enabled the Corporation to spread relatively fixed operating costs over higher production volumes.

Energy and non-energy operating costs are partially offset by power sales which were lower in 2012 compared to 2011 due to a decrease in realized power prices. Primarily as a result of lower natural gas prices, MEG's power sales had the effect of offsetting 92% of energy operating costs during 2012.

Cash operating netback for 2012 was $34.18 per barrel compared to $43.15 per barrel for 2011. Cash operating netbacks were negatively impacted by the decrease in the Corporation's bitumen realizations due to the wider differentials to WTI in 2012 compared to 2011. The decrease was partially offset by an increase in production and a reduction in energy operating costs in 2012.

Capital investment increased to $1.6 billion in 2012 from $928.9 million in 2011. Capital investment in 2012 was focused on the construction of Phase 2B, delineation drilling and seismic programs at Christina Lake and Surmont, the RISER production enhancement program, construction of the Stonefell Terminal, and expansion of the Access Pipeline.

Net income for 2012 was $52.6 million compared to $63.8 million for 2011. Net income in 2012 included a net foreign exchange gain of $36.6 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 loss of $35.7 million in 2011. Net income was also impacted by lower realized bitumen prices and higher production volumes in 2012 compared to 2011.

Operating earnings for 2012 were $21.2 million compared to $109.3 million for 2011. The decrease in operating earnings for 2012 compared to 2011 is due to lower bitumen realizations, higher general and administrative expense and higher interest expense, partially offset by higher production and lower operating costs.

Cash flow from operations was $212.5 million in 2012, compared to $304.6 million in 2011. Cash flow from operations was impacted by the same factors that impacted operating earnings.

The Corporation's cash and short-term investments balance was $2.0 billion as at December 31, 2012 compared to $1.6 billion as at December 31, 2011. Long-term debt increased to $2.5 billion as at December 31, 2012 from $1.8 billion as at December 31, 2011. 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. A total of 12.1 million of the common shares were issued through a public bought deal financing while the remaining 12.1 million common shares were issued on a private placement basis.

As at December 31, 2012, the Corporation's capital resources included $2.0 billion of cash and short-term investments and an undrawn US$1.0 billion revolving credit facility. In March 2012, MEG expanded its undrawn senior secured revolving credit facility from US$500.0 million to US$1.0 billion and extended the maturity to March 2017.

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 a planned plant turnaround 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 exit rates of 37,000 to 43,000 bpd by the end of the year. Annual non-energy operating costs are anticipated to be in the range of $9 to $11 per barrel.

The Corporation's 2013 planned capital investment totals approximately $2.0 billion, including approximately $135 million deferred from previously planned 2012 investments. Excluding the capital carry-over from 2012, approximately $500 million of the capital budget will be directed towards the RISER initiative, which is focused on increasing production and throughput capacity in the near-term from the Corporation's existing facilities. The Corporation plans to invest approximately $700 million in growth capital at the Christina Lake project. Planned investment includes $170 million to complete construction of Phase 2B, $100 million for 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), and $220 million for engineering, long lead items and site preparation for Phase 3A. Approximately $360 million will be directed towards infrastructure investments to expand the jointly-owned Access Pipeline and complete the 900,000 barrel Stonefell Terminal in mid-2013.

Business Environment

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

	Year Ended December 31		2012				2011			
	2012	2011	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Commodity Prices (Average Prices)										
Crude oil prices										
West Texas Intermediate (WTI) US$/bbl	**94.21**	95.12	**88.18**	**92.22**	**93.49**	**102.92**	94.06	89.76	102.56	94.10
Western Canadian Select (WCS) C$/bbl	**73.13**	77.15	**69.47**	**70.06**	**71.34**	**81.66**	85.53	70.68	82.17	70.23
Differential – WTI/WCS (C$/bbl)	**21.01**	16.95	**17.94**	**21.67**	**23.10**	**21.39**	10.70	17.31	17.08	22.55
Differential – WTI/WCS	**22.3%**	18.0%	**20.5%**	**23.6%**	**24.5%**	**20.8%**	11.1%	19.7%	17.2%	24.3%
Natural gas prices										
AECO (C$/mcf)	**2.39**	3.66	**3.04**	**2.18**	**1.83**	**2.50**	3.45	3.70	3.72	3.76
Electric power prices										
Alberta power pool average price (C$/MWh)	**64.24**	76.17	**78.73**	**78.09**	**40.03**	**60.10**	76.05	94.69	51.90	82.03
Foreign exchange rates										
C$ equivalent of 1 US$ - average	**0.9994**	0.9893	**0.9913**	**0.9948**	**1.0102**	**1.0012**	1.0231	0.9802	0.9676	0.9860
C$ equivalent of 1 US$ - period end	**0.9949**	1.0170	**0.9949**	**0.9837**	**1.0191**	**0.9991**	1.0170	1.0389	0.9643	0.9718

WTI price 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 WTI price for 2012 was US$94.21 per barrel compared to US$95.12 per barrel in 2011.

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 discount to the WTI benchmark price. In 2012, the WTI/WCS differential averaged 22.3% compared to 18.0% during 2011.

Increases in production of both light crude oil and heavier crudes have put pressure on both light and heavy oil prices in the U.S. mid-continent. Pipeline congestion and refinery outages in the U.S. Midwest added to this pressure which led to a larger discount for Canadian crude in 2012. A number of initiatives to access additional markets, including the expansion in capacity of the Seaway pipeline in early 2013, completion of the 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 property is mixed with purchased diluent. The end product is marketed as a bitumen blend known as Access Western Blend ("AWB" or "blend"). It is shipped through the Access Pipeline to the Edmonton-area refining and transportation hub. The differential between WTI and MEG's blend sales widened to an average of 31.2% in 2012 from 23.5% during 2011. The completion of MEG's Stonefell Terminal combined with the initiation of rail and barging alternatives in mid-2013 are expected to enable MEG to avoid pipeline bottlenecks and shift product pricing from the discounted Edmonton and mid-continent markets to higher value markets on the east coast and U.S Gulf Coast. In addition, the Corporation has secured strategic pipeline capacity commencing in mid-2014 along with opportunities to move products to a wider range of markets. These include pipeline connections to rail loading facilities at Bruderheim, Alberta and the leasing of barges for use on the U.S. Inland Waterways, both of which, along with the Stonefell Terminal, are expected to become available for use in mid-2013.

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 $2.39 per mcf in 2012, compared to $3.66 per mcf in 2011. Natural gas prices have trended lower over the past three years as a result of strong supply growth throughout North America.

The Alberta power pool price averaged $64.24 per megawatt hour in 2012, compared to $76.17 per megawatt hour in 2011. Power prices for 2012 were lower due to mild winter weather, lower natural gas prices and power supply additions to the Alberta grid.

Increases in the value of the Canadian dollar relative to the U.S. dollar have a negative impact on the Corporation's bitumen revenues, as sales prices are determined by reference to U.S. benchmarks. The negative impact on bitumen revenues is partially offset by lower principal and interest payments on the Corporation's U.S. dollar denominated debt. As at December 31, 2012, the Canadian dollar, at a rate of 0.9949, had increased by approximately $0.02 in value against the U.S. dollar compared to its value as at December 31, 2011, when the rate was 1.0170.

Results of Operations

	2012	2011
Bitumen production – bpd	**28,773**	26,605
Steam to oil ratio	**2.4**	2.4

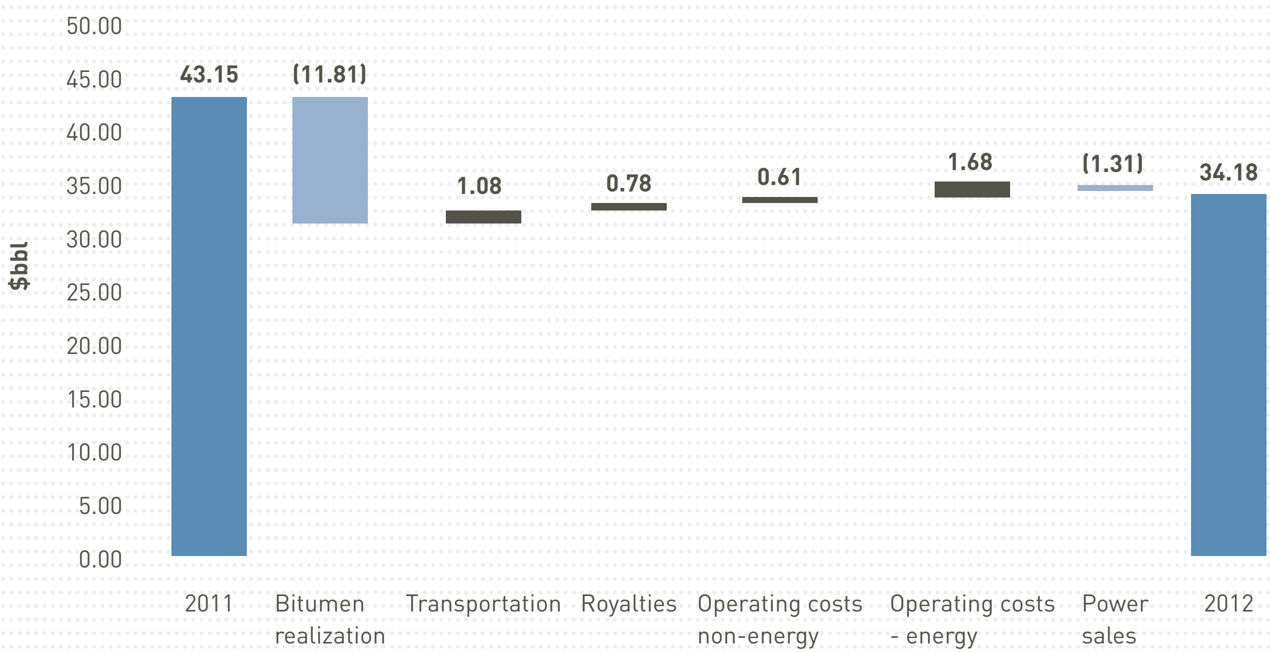
Production

Production averaged 28,773 bpd in 2012 compared to 26,605 bpd in 2011. The increase in production primarily results from increased steam generation capabilities in 2012 compared to the same periods in 2011. Plant efficiencies, combined with improvements made to the Corporation's existing steam generation system during the plant turnaround that occurred in the third quarter of 2011, enabled the additional six well pairs and two infill wells to be placed on production. There were 41 SAGD well pairs and two infill wells on production as at December 31, 2012, in comparison to 35 SAGD well pairs on production as at December 31, 2011.

The average steam to oil ratio ("SOR") for 2012 was 2.4, compared to an average SOR of 2.4 in 2011. 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 2012 versus 2011:



The following table summarizes the Corporation's cash operating netback for the years ended December 31:

	2012		2011	
	$000	$ per bbl	$000	$ per bbl
Bitumen realization[1]	495,425	46.93	570,027	58.74
Transportation[2]	(3,231)	(0.31)	(13,476)	(1.39)
Royalties	(25,959)	(2.46)	(31,438)	(3.24)
Net bitumen revenue	466,235	44.16	525,113	54.11
Operating costs – non-energy	(102,481)	(9.71)	(100,162)	(10.32)
Operating costs – energy	(36,538)	(3.46)	(49,867)	(5.14)
Power sales	33,634	3.19	43,628	4.50
Net operating costs	(105,385)	(9.98)	(106,401)	(10.96)
Cash operating netback[3]	360,850	34.18	418,712	43.15

[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," 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.

($000)	2012	2011
Blend sales – proprietary volumes	991,975	1,021,036
Cost of diluent	(496,550)	(451,009)
Bitumen realization	495,425	570,027

Blend sales for 2012 were $992.0 million compared to $1.0 billion for 2011. Blend sales averaged $64.78 per barrel in 2012 compared to $72.03 per barrel in 2011. The decrease in blend sales is due to the lower average realized price partially offset by higher sales volumes.

The cost of diluent was $496.6 million in 2012, compared to $451.0 million in 2011. On a per barrel basis, the Corporation's cost of diluent increased to $104.41 per barrel for 2012, from $100.87 per barrel in 2011. The cost of diluent increased due to higher volumes of diluent purchased as a result of increased production, in addition to higher 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 on diluent transportation arrangements, were $3.2 million for 2012 compared to $13.5 million for 2011. On a per barrel basis, transportation costs decreased to an average of $0.31 per barrel during 2012, from $1.39 per barrel during 2011. The decrease in transportation costs in 2012 compared to 2011 is primarily due to higher third-party recoveries on diluent transportation arrangements, which totaled $13.0 million in 2012, compared to $3.4 million in 2011.

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 $26.0 million in 2012 compared to $31.4 million in 2011, or an average of $2.46 per barrel for 2012, compared to $3.24 per barrel in 2011. The Corporation's royalty rate was 5.2% of bitumen realizations for 2012, compared to 5.5% for 2011. The decrease in royalties is attributable to lower bitumen realizations.

Operating Costs

Non-energy related operating costs were $102.5 million in 2012, compared to $100.2 million in 2011, and decreased to an average of $9.71 per barrel from $10.32 per barrel in 2011. On a per barrel basis, non-energy related operating costs decreased primarily as a result of higher production, as relatively fixed components of operating costs are spread over a greater number of barrels of production.

Energy related operating costs were $36.5 million compared to $49.9 million in 2011. On a per barrel basis, energy operating costs were $3.46 per barrel compared to $5.14 per barrel for 2011. The decrease in energy related operating costs per barrel is primarily the result of lower natural gas prices. The benchmark AECO natural gas price averaged $2.39 per mcf in 2012, compared to $3.66 per mcf for 2011. Natural gas prices have trended lower over the past three years as a result of strong supply growth throughout North America.

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 $33.6 million in 2012, compared to $43.6 million for 2011. The Corporation realized an average power price of $59.22 per megawatt hour for 2012, compared to $74.33 per megawatt hour in 2011. 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. Power prices for 2012 were lower due to mild winter weather and additional power supply as a result of the commissioning of a 450 megawatt power plant in Alberta during September 2011. Power prices have also been affected by lower natural gas prices.

Non-IFRS Measurements

The following tables reconcile the non-IFRS measurements "Operating earnings" and "Cash operating netback" to "Net income" the nearest IFRS measure, and also reconcile the non-IFRS measurement "Cash flow from operations" to "Net cash provided by operating activities", the nearest IFRS measure. Operating earnings is defined as net income as reported, excluding the after-tax unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial liabilities, unrealized fair value gains or losses on other assets and gain on modification of long-term debt. Cash flow from operations excludes debt modification costs and the net change in non-cash operating working capital, while the IFRS measurement "Net cash provided by 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.

($000)	2012	2011
Net income	52,569	63,837
Add (deduct):		
Unrealized foreign exchange (gain) loss, net of tax[1]	(39,090)	39,383
Unrealized loss on derivative financial liabilities, net of tax[2]	9,651	8,115
Unrealized fair value gain on other assets[3]	(1,888)	-
Gain on modification of long-term debt, net of tax[4]	-	(2,080)
Operating earnings	21,242	109,255
Add (deduct):		
Interest income	(19,896)	(18,786)
Depletion and depreciation	144,950	124,327
General and administrative	70,597	55,738
Stock-based compensation	25,246	21,355
Research and development	5,157	6,810
Interest expense	91,816	73,647
Accretion	3,670	1,646
Gain on disposition of asset	(3,075)	-
Realized (gain) loss on foreign exchange	(796)	506
Realized loss on derivative financial liabilities	4,518	532
Net marketing activity	1,762	-
Deferred income taxes, operating	15,659	43,682
Cash operating netback	360,850	418,712

[1] Unrealized foreign exchange gains and losses result primarily from the translation of U.S. dollar denominated long-term debt, cash and cash equivalents to period-end exchange rates. Unrealized foreign exchange gains and losses are presented net of a deferred tax recovery of $3,269 for the year ended December 31, 2012 (deferred tax expense of $4,176 for the year ended December 31, 2011).

[2] Unrealized 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 recovery of $3,217 for the year ended December 31, 2012 (deferred tax recovery of $2,704 for the year ended December 31, 2011).

[3] Unrealized fair value gain on other assets results from the fair market valuation of certain investments held at December 31, 2012, net of a deferred tax expense of $630 for the year ended December 31, 2012.

[4] Gain on modification of long-term debt results from modifications to the Corporation's senior secured credit facility on March 18, 2011, net of a deferred tax expense of $693 for the year ended December 31, 2011.

Non-IFRS Measurements - Reconciliation of net cash provided by operating activities to cash flow from operations ($000)	2012	2011
Net cash provided by operating activities	240,824	314,302
Add (deduct):		
Net change in non-cash operating working capital items	(28,310)	(18,098)
Debt modification costs	-	8,423
Cash flow from operations	212,514	304,627

Interest and Other Income

Interest and other income was $19.9 million compared to $18.8 million in 2011. The increase is mainly due to higher interest rates and other income realized on cash and short-term investments held in 2012 compared to 2011.

Depletion and Depreciation

Depletion and depreciation expense was $145.0 million, compared to $124.3 million for 2011. The increase is primarily due to higher production volumes and an increase in the rate per barrel as a result of higher estimated future development costs of the producing oil sands properties. The future development costs are a key element of the rate determination. Depletion and depreciation expense in 2011 included $5.3 million of capital costs associated with derecognizing a SAGD well that required replacement ($nil in 2012). The depletion and depreciation rate for 2012 was $13.76 per barrel, compared to $12.81 per barrel for 2011. 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

($000)	2012	2011
General and administrative costs	91,510	69,861
Capitalized general and administrative costs	(20,913)	(14,123)
General and administrative expense	70,597	55,738

General and administrative expense for 2012 was $70.6 million, compared to $55.7 million in 2011. 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 $25.2 million for the year ended December 31, 2012, compared to $21.4 million for 2011. The Corporation capitalizes a portion of stock-based compensation expense associated with capitalized salaries and benefits. The Corporation capitalized $6.8 million of stock-based compensation to property, plant and equipment in 2012, compared to $5.1 million in 2011.

Research and Development

Research and development expenditures related to the Corporation's research of greenhouse gas management, crude quality improvement and related technologies have been expensed. Research and development expenditures were $5.2 million in 2012, compared to $6.8 million in 2011.

Gain on Disposition of Assets

During the first quarter of 2012, the Corporation sold a portion of its interest in certain connections on the Access Pipeline. The Corporation's net investment in these connections was $4.4 million and the proceeds were $7.5 million, resulting in a gain of $3.1 million (2011 – $nil).

Net Finance Expense

($000)	2012	2011
Total interest expense	122,424	88,276
Less capitalized interest	(30,608)	(14,629)
Net interest expense	91,816	73,647
Accretion on decommissioning provision	3,670	1,646
Unrealized fair value loss on embedded derivative financial liabilities	2,953	8,346
Unrealized fair value loss on interest rate swaps	9,915	2,473
Realized loss on interest rate swaps	4,518	532
Unrealized fair value gain on other assets	(2,518)	-
Net finance expense	110,354	86,644

Total interest expense was $122.4 million for the year ended December 31, 2012, compared to $88.3 million for the year ended December 31, 2011. Total interest expense increased primarily as a result of the increased debt outstanding in 2012. Effective July 19, 2012, the Corporation issued US$800.0 million of 6.375% senior unsecured notes.

The Corporation recognized an unrealized loss on embedded derivative financial liabilities of $3.0 million during 2012, compared to a loss of $8.3 million in 2011. These losses relate to the change in fair value of the interest rate floor associated with the Corporation's senior secured credit facilities. The interest rate floor is considered an embedded derivative as the floor rate was higher than the London Interbank Offered Rate ("LIBOR") at the time that the debt agreement was entered into. Accordingly, the original fair value of the embedded derivative at the time the debt agreement was entered into was netted against the carrying value of the long-term debt and will be amortized over the life of the debt agreement. 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$987.5 million senior secured term loan until September 30, 2016. The Corporation realized a $4.5 million loss for the year ended December 31, 2012 compared to a realized loss of $0.5 million for the year ended December 31, 2011. In addition, the Corporation recognized a $9.9 million unrealized loss on the interest rate swaps in 2012, compared to a $2.5 million unrealized loss in 2011.

The unrealized fair value gain on other assets of $2.5 million (2011 – $nil) relates to a net increase in the fair value of notes held by the Corporation. The notes are classified as held-for-trading which requires them to be measured at fair value at each period end with the resulting change in fair value recognized within net income.

Net Foreign Exchange Gain (Loss)

($000)	2012	2011
Foreign exchange gain (loss) on:		
Long-term debt	48,822	(46,856)
US$ denominated cash and cash equivalents	(13,000)	11,649
Other	796	(506)
Net foreign exchange gain (loss)	36,618	(35,713)

Cdn$-US$ exchange rate as at December 31,	2012	2011	2010
C$ equivalent of 1 US$	0.9949	1.0170	0.9946

The net foreign exchange gain for the year ended December 31, 2012 was $36.6 million in comparison to a net foreign exchange loss of $35.7 million in 2011. The Canadian dollar strengthened by approximately $0.02 over the course of 2012, while in 2011 the Canadian dollar weakened by approximately $0.02.

Net Marketing Activity

($000)	2012	2011
Sales of purchased product	37,822	-
Purchased product and storage	(39,584)	-
Net marketing activity	(1,762)	-

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 expense of $9.8 million in 2012, compared to a deferred income tax expense of $45.8 million in 2011.

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 year ended December 31, 2012, the non-taxable gain was $24.4 million compared to a non-taxable loss of $23.4 million in 2011.

> At the end of 2011, the Corporation had not recognized the tax benefit related to $28.5 million in unrealized taxable capital foreign exchange losses. With the strengthening of the Canadian dollar by approximately $0.02 during 2012, the Corporation was able to recognize $24.5 million of this tax benefit.

> Non-taxable stock-based compensation was $25.2 million for 2012, in comparison to $21.4 million for 2011.

The Corporation is not currently taxable. As of December 31, 2012, the Corporation had approximately $3.6 billion of available tax pools and had recognized a deferred income tax liability of $71.4 million. In addition, at December 31, 2012, the Corporation had $1.8 billion of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

Summary of Quarterly Results

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

	2012				2011			
($ millions, except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	297.6	213.7	259.7	279.6	326.5	175.9	279.9	254.4
Net income (loss)	(18.7)	47.5	(29.5)	53.4	91.1	(115.2)	42.5	45.4
Per share – basic	(0.09)	0.24	(0.15)	0.28	0.47	(0.60)	0.22	0.24
Per share – diluted	(0.09)	0.24	(0.15)	0.27	0.46	(0.60)	0.21	0.23

Revenue for the eight most recent quarters has been impacted by an increase in production, partially offset by decreased bitumen realizations during 2012. 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;

> risk management activities for interest rate swaps;

> net gains and losses on the modification of long-term debt;

> 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.

The Corporation's unaudited fourth quarter 2012 results were discussed and analyzed in the Corporation's January 31, 2013 press release, which is available on the Corporation's website at www.megenergy.com or at www.sedar.com.

Capital Investing

Summary of capital investment ($000)	2012	2011
Christina Lake Phase 2B	631,495	466,341
Christina Lake Phase 3	80,288	4,327
RISER and other enhancements	234,277	76,078
Delineation drilling and seismic	127,959	87,106
Regulatory	5,577	2,585
Other	47,581	91,671
Growth	**1,127,177**	**728,108**
Access Pipeline	115,807	41,895
Stonefell Terminal	136,399	10,439
Field infrastructure	100,066	86,133
Infrastructure related to growth	**352,272**	**138,467**
Sustaining and maintenance	67,275	23,857
Capitalized interest and fees	30,608	14,629
Other	21,182	23,860
Total cash capital investment	**1,598,514**	**928,921**
Non-cash	21,169	55,705
Total capital investment	**1,619,683**	**984,626**

MEG's capital investment for the year ended December 31, 2012 totalled $1.6 billion, compared to $984.6 million invested during the year ended December 31, 2011. Capital investment included $1.1 billion in growth focused investment during 2012, compared to $728.1 million in 2011.

MEG invested $631.5 million on Phase 2B of the Christina Lake project in 2012, which was directed towards detailed engineering, the purchase of major equipment and materials, and construction activities. As at December 31, 2012, detailed engineering was complete and all modules had been installed. All materials have been ordered and delivered, with on-site construction scheduled to continue toward targeted completion and start-up in the second half of 2013.

MEG invested $234.3 million during 2012 on RISER and other operational enhancements at the Christina Lake project. This included the drilling of 16 infill wells and two additional SAGD well pairs which are scheduled to be brought into production during the second half of 2013. These activities are aimed at further improving the operational performance of the Corporation's wells and facilities.

For the year ended December 31, 2012, the Corporation invested $128.0 million on delineation drilling and seismic. The Corporation drilled 113 core holes, 11 observation wells and five water wells to support Phase 2B horizontal well placement and to further delineate the resource base at Christina Lake. A total of ten core holes were completed on Surmont leases. These core holes, combined with the acquisition of high resolution 3D seismic, were used to increase resource definition on the Surmont leases to support regulatory applications filed in September 2012. In addition, 22 core holes were drilled on the Growth Properties with the intent of increasing resource definition and continuing to build an inventory of potentially commercial projects.

A total of $352.3 million was invested in the Corporation's growth-related infrastructure during 2012. Of this total, the Corporation invested $115.8 million primarily on regulatory and engineering work and material purchases related to the expansion of the jointly-owned Access Pipeline. Regulatory approval of the pipeline expansion was received on November 30, 2012 and initial construction activities have commenced. Investment in the Stonefell Terminal amounted to $136.4 million during 2012. The Stonefell Terminal is a 900,000 barrel tank farm located east of the Access Pipeline Sturgeon Terminal, and is expected to be operational in mid-2013. The Corporation invested a total of $100.1 million in support infrastructure for current operations at Christina Lake.

The Corporation capitalizes interest expense and certain finance charges associated with undeveloped property acquisitions and major development projects. Interest associated with the development of growth capital projects is capitalized. During 2012, $30.6 million was capitalized in comparison to $14.6 million in 2011.

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

Non-cash capital investment in 2012 included $21.2 million (2011 - $55.7 million), for future decommissioning of the Corporation's property, plant and equipment.

Liquidity and Capital Resources

($000, except as noted)	2012	2011
Cash and short term investments	2,007,841	1,647,069
Senior secured term loan (December 31, 2012 - US$987.5 million; December 31, 2011 – US$997.5 million; due 2018)	982,464	1,014,458
US$1.0 billion revolver due 2017	-	-
6.5% senior unsecured notes (US$750.0 million; due 2021)	746,175	762,750
6.375% senior unsecured notes (US$800.0 million; due 2023)	795,920	-
Total debt[1]	2,524,559	1,777,208
Shareholders' equity	4,870,534	3,984,104
Total book capitalization[2]	7,395,093	5,761,312
Total debt/book capitalization[2]	34.1%	30.8%
Market capitalization[3]	6,274,940	8,221,813
Total debt/(debt plus market capitalization)[3]	28.7%	17.8%

[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 December 31, 2012.

[2] Non-IFRS measurements and related metrics that use total debt plus shareholders' equity.

[3] Non-IFRS measurements and metrics that use total debt and market capitalization. Market capitalization is based on a weighted average of 206,141,261 diluted shares outstanding as at December 31, 2012 (December 31, 2011 – 197,782,367) and a $30.44 closing share price on December 31, 2012 ($41.57 on December 31, 2011).

Capital Resources

As at December 31, 2012, the Corporation's capital resources included $1.7 billion of working capital and an additional undrawn US$1.0 billion revolving credit facility. Working capital is comprised of $2.0 billion of cash, cash equivalents and short-term investments, offset by a non-cash working capital deficiency of $0.3 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 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 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 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.

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. A total of 12.1 million common shares were issued through a public bought deal financing while the remaining 12.1 million common shares were issued on a private placement basis.

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.

In March 2011, the Corporation refinanced its existing senior secured term loans and revolving credit facilities. The Corporation extended the maturity date of the term loans to March 18, 2018 and reduced the interest rate from LIBOR plus 400 basis points to LIBOR plus 300 basis points.

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$987.5 million senior secured term loan until September 30, 2016.

On March 18, 2011 the Corporation issued US$750.0 million in aggregate principal amount of 6.5% senior unsecured notes, with interest paid semi-annually. The notes are due on March 15, 2021. The $14.4 million cost of the transaction was deferred and is being amortized over the life of the notes.

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

($000)	2012	2011
Net cash provided by (used in):		
Operating activities	**240,824**	314,302
Investing activities	**(1,820,520)**	(813,783)
Financing activities	**1,572,408**	758,517
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**(13,000)**	11,649
Change in cash and cash equivalents	**(20,288)**	270,685

Cash Flows - Operating Activities

Net cash provided by operating activities in 2012 was $240.8 million compared to $314.3 million for 2011. The decrease in cash flows from operating activities was primarily due to lower bitumen realizations, higher general and administrative expense and higher interest expense, partially offset by higher production and lower operating costs.

Cash Flows - Investing Activities

Net cash used for investing activities for 2012 was $1.8 billion compared to $813.8 million in 2011. The increase in net cash used for investing activities is due to the increase in capital investments and the change in non-cash investing working capital. Refer to the "CAPITAL INVESTING" section of this MD&A for further details.

Cash Flows - Financing Activities

Net cash provided by financing activities for 2012 includes: $774.8 million of net proceeds from the issuance of 24.3 million common shares at a price of $33.00 per share; the $792.6 million in net proceeds from the senior unsecured notes issuance; and $20.7 million in proceeds received from the exercise of stock options. These amounts were partially offset by $10.0 million of debt principal repayment on the senior secured term loan and $5.6 million of fees associated with the revolving credit facility amendment.

Financing activities during 2011 included: $723.8 million of net proceeds received from the Corporation's issuance of US$750.0 million senior unsecured notes; $39.7 million in proceeds received from the exercise of stock options, net of $3.0 million in fees associated with amendments to the Corporation's credit facility; and $2.5 million in debt principal repayment on the senior secured term loan.

Shares Outstanding

As at December 31, 2012, the Corporation had the following share capital instruments outstanding:

Common shares	220,190,084
Convertible securities	
Stock options outstanding – exercisable and unexercisable	9,147,404
Restricted share units outstanding	953,804

As at February 15, 2013, the Corporation had 221,083,951 common shares, 8,245,497 stock options and 949,008 restricted share units outstanding.

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]	2,524,559	9,949	19,898	19,898	2,474,814
Interest on long-term debt[1]	1,109,044	138,391	275,587	273,995	421,071
Decommissioning obligation[2]	228,134	1,542	3,784	-	222,808
Pipeline transportation[3]	1,401,634	984	61,318	121,818	1,217,514
Contracts and purchase orders[4]	1,060,080	919,575	90,419	13,945	36,141
Operating leases[5]	123,470	10,986	22,145	23,108	67,231
	6,446,921	1,081,427	473,151	452,764	4,439,579

[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 December 31, 2012.
[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.

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.

In 2011, the Corporation changed its accounting policy from using a risk-free rate, to a credit-adjusted rate to calculate the discounted value of the estimated future cash outflows required to settle the decommissioning obligation. This change was applied retrospectively.

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.

Transactions with Related Parties

The Corporation did not enter into any related party transactions during the years ended December 31, 2012 or December 31, 2011, other than compensation of key management personnel. The Corporation considers directors and executive officers as key management personnel.

($000)	2012	2011
Salaries and short-term employee benefits	8,489	7,254
Share-based compensation expense	9,885	8,015
	18,374	15,269

Off-Balance Sheet Arrangements

At December 31, 2012 and 2011, the Corporation did not have any off-balance sheet arrangements.

New Accounting Policies

The Corporation has not applied any new accounting policies for the year ended December 31, 2012.

Accounting standards issued but not yet applied

The IASB has issued the following standards which have not yet been adopted by the Corporation: IFRS 9, Financial Instruments; IFRS 10, Consolidated Financial Statements; IFRS 11, Joint Arrangements; IFRS 12, Disclosure of Interests in Other Entities; and IFRS 13, Fair Value Measurement. Also, the IASB has amended the following standards which have not yet been adopted by the Corporation: IAS 1, Presentation of Financial Statements; IAS 19, Employee Benefits; IAS 27 Separate Financial Statements; IAS 28, Investments in Associates and Joint Ventures; IAS 32, Financial Instruments: Presentation; and IFRS 7, Financial Instruments: Disclosure. The new standards, except IFRS 9 and the amendments to IAS 1 and IAS 32, are effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. The effective date of IFRS 9 is for annual periods beginning on or after January 1, 2015 with early adoption permitted. The amendments to IAS 1 are effective for periods beginning on or after July 1, 2012. The amendments to IAS 32 are effective for periods beginning on or after January 1, 2014. The Corporation has performed an initial assessment of the impact of the new and amended standards and does not currently expect that the adoption of these standards will have a significant impact on the Corporation's financial statements.

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

IFRS 9 is the first step to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12, Consolidation—Special Purpose Entities, and parts of IAS 27, Consolidated and Separate Financial Statements.

IFRS 11 requires an entity to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting, whereas for a joint operation, the entity will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, Interests in Joint Ventures, and SIC-13, Jointly Controlled Entities—Non-monetary Contributions by Venturers.

IFRS 12 establishes disclosure requirements for interests in other entities, such as joint arrangements, associates, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities.

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures.

IAS 1 Presentation of Financial Statements was amended in June 2011 to require entities to group separately within other comprehensive income those items which may be subsequently reclassified to profit or loss from those that will not and to require the tax associated with items presented before tax to be shown separately for each of the two groups. The amendments to IAS 1 are applicable to annual periods beginning on or after July 1, 2012.

IAS 19 has been amended to 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. A number of other amendments have been made to recognition, measurement and classification including redefining short-term and other long-term benefits, guidance on the treatment of taxes related to benefit plans, guidance on risk/cost sharing features, and expanded disclosures.

IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 – 13. IFRS 7 and IAS 32 were amended to clarify the requirements for the offsetting of financial assets and financial liabilities on the balance sheet and to enhance the disclosure requirements pertaining to the offsetting of financial assets and financial liabilities on the balance sheet.

Risk Factors

The Corporation's primary focus is on the ongoing development and operation of its oil sands assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including the risks which have been categorized below as construction risks, operations risks and project development risks. Further information regarding the risk factors affecting the Corporation is contained in the Annual Information Form.

Risks Arising from Construction Activities

Cost and Schedule Risk

Additional phases of development of the Christina Lake project and the development of the Corporation's other projects may suffer from delays, cancellation, interruptions or increased costs due to many factors, some of which may be beyond the Corporation's control, including:

- engineering, construction and/or procurement performance falling below expected levels of output or efficiency;
- denial or delays in receipt of regulatory approvals, additional requirements imposed by changes in laws or non-compliance with conditions imposed by regulatory approvals;
- labour disputes or disruptions, declines in labour productivity or the unavailability of skilled labour;
- increases in the cost of labour and materials; and
- changes in project scope or errors in design.

If any of the above events occur, they could have a material adverse effect on the Corporation's ability to continue to develop the Christina Lake project, the Corporation's facilities or the Corporation's other future projects and facilities, which would materially adversely affect its business, financial condition and results of operations.

Risks Arising from Operations

Operating Risk

The operation of the Corporation's oil sands properties and projects are and will continue to be subject to the customary hazards associated with recovering, transporting and processing hydrocarbons, such as fires, severe weather, natural disasters (including wildfires), explosions, gaseous leaks, migration of harmful substances, blowouts and spills. A casualty occurrence might result in the loss of equipment or life, as well as injury, property damage or the interruption of the Corporation's operations. The Corporation's insurance may not be sufficient to cover all potential casualties, damages, losses or disruptions. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Operating Results

The Corporation's operating results are affected by many factors. The principal factors, amongst others, which could affect MEG's operating results include:

- a substantial decline in oil, bitumen or electricity prices, due to a lack of infrastructure or otherwise;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher steam-to-oil ratios;
- a lack of access to or an increase in the cost of diluent;
- an increase in the cost of natural gas;
- the reliability and maintenance of the Access Pipeline and MEG's other facilities;
- the need to repair existing horizontal wells, or the need to drill additional horizontal wells;
- the ability and cost to transport bitumen, diluent and bitumen diluent blends, and the cost to dispose of certain by-products;
- increased royalty payments resulting from changes in the regulatory regime;
- a lack of sufficient pipeline or electrical transmission capacity, and the effect that an apportionment may have on MEG's access to such capacity;
- the cost of labour, materials, services and chemicals used in MEG's operations; and
- the cost of compliance with existing and new regulations.

Labour Risk

The Corporation depends on its management team and other key personnel to run its business and manage the operation of its projects. The loss of any of these individuals could adversely affect the Corporation's operations. Due to the specialized nature of the Corporation's business, the Corporation believes that its future success will also depend upon its ability to continue to attract, retain and motivate highly skilled management, technical, operations and marketing personnel.

Project Development Risks

Reliance on Third Parties

The Christina Lake project and the Corporation's future projects will depend on the successful operation and the adequate capacities of certain infrastructure owned and operated by third parties or joint ventures with third parties, including:

- pipelines for the transport of natural gas, diluent and blended bitumen;
- power transmission grids supplying and exporting electricity; and
- other third party transportation infrastructure such as roads, rail, terminals, barges and airstrips.

The failure or lack of any or all of the infrastructure described above will negatively impact the operation of the Christina Lake project and MEG's future projects, which, in turn, may have a material adverse effect on MEG's business, results of operations and financial condition.

Reserves and Resources

There are numerous uncertainties inherent in estimating quantities of in-place bitumen reserves and resources, including many factors beyond the Corporation's control. In general, estimates of economically recoverable bitumen reserves and resources and the future net cash flow therefrom are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the effects of regulation by governmental agencies, and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results.All such estimates are, to some degree, uncertain and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, the classification of such reserves and resources based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

Although third parties have prepared the GLJ Report and other reviews, reports and projections relating to the viability and expected performance of the Christina Lake project, the Surmont project and the Growth Properties, the GLJ Report, the reviews, reports and projections and the assumptions on which they are based may not, over time, prove to be accurate. Actual production and cash flow derived from the Corporation's oil sands leases may vary from the GLJ Report and other reviews, reports and projections.

Financing Risk

Significant amounts of capital will be required to develop future phases of the Christina Lake project, the Surmont project and the Growth Properties. At present, cash flow from the Corporation's operations is largely dependent on the performance of a single project and the major source of funds available to the Corporation is the issuance of additional equity or debt. Capital requirements are subject to capital market risks, including the availability and cost of capital. There can be no assurance that sufficient capital will be available or be available on acceptable terms or on a timely basis, to fund the Corporation's capital obligations in respect of the development of its projects or any other capital obligations it may have. The Corporation may not generate sufficient cash flow from operations and may not have additional equity or debt available to it in amounts sufficient to enable it to make payments with respect to its indebtedness or to fund its other liquidity needs. In these circumstances, the Corporation may need to refinance all or a portion of its indebtedness on or before maturity. The Corporation may not be able to refinance any of its indebtedness on commercially reasonable terms or at all.

Commodity Price Risk

The Corporation's business, financial condition, results of operations and cash flow are dependent upon the prevailing prices of its bitumen blend, condensate, power and natural gas. Prices of these commodities have historically been extremely volatile and fluctuate significantly in response to regional, national and global supply and demand, and other factors beyond the Corporation's control.

Declines in prices received for the Corporation's bitumen blend could materially adversely affect the Corporation's business, financial position, results of operations and cash flow. In addition, any prolonged period of low bitumen blend prices or high natural gas or condensate prices could result in a decision by the Corporation to suspend or reduce production. Any suspension or reduction of production would result in a corresponding decrease in the Corporation's revenues and could materially impact the Corporation's ability to meet its debt service obligations.

Interest Rate Risk

The Corporation has obtained certain credit facilities to finance a portion of the capital costs of the Christina Lake project and to fund the Corporation's other development and acquisition activities. Variations in interest rates could result in significant changes to debt service requirements and would affect the financial results of the Corporation. If over-the-counter derivative structures are employed to mitigate interest rate risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Foreign Currency Risk

The Corporation's credit facilities are denominated in U.S. dollars and prices of the Corporation's bitumen blend are generally based on U.S. dollar market prices. Fluctuations in U.S. and Canadian dollar exchange rates may cause a negative impact on revenue, costs and debt service obligations and may have a material adverse impact on the Corporation. If over-the-counter derivative structures are employed to mitigate foreign currency risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Regulatory and Environmental Risk

The oil and gas industry in Canada, including the oil sands industry, operates under Canadian federal, provincial and municipal legislation and regulations. Future development of the Christina Lake project, the Surmont project and the Growth Properties is dependent on the Corporation maintaining its current oil sands leases and licences and receiving required regulatory approvals and permits on a timely basis. The Government of Alberta has initiated a process to control cumulative environment effects of industrial development through the Lower Athabasca Regional Plan ("LARP"). While the LARP has not had a significant effect on the Corporation, there can be no assurance that changes to the LARP or future laws or regulations will not adversely impact the Corporation's ability to develop or operate its projects.

The Corporation is committed to meeting its responsibilities to protect the environment and fully comply with all environmental laws and regulations. Alberta regulates emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("GHG"), and Canada's federal government has proposed significant extensions to its GHG regulatory requirements, which currently deal only with reporting. The direct and indirect costs of the various regulations, existing, proposed and future, may adversely affect MEG's business, operations and financial results. The emission reduction compliance obligations required under existing and future federal and provincial industrial air pollutant and GHG emission reduction targets and requirements, together with emission reduction requirements in future regulatory approvals, may not be technically or economically feasible to implement for MEG's bitumen recovery and cogeneration activities. Any failure to meet MEG's emission reduction compliance obligations may materially adversely affect MEG's business and result in fines, penalties and the suspension of operations.

Royalty Risk

The Corporation's revenue and expenses will be directly affected by the royalty regime applicable to its oil sands development. The Government of Alberta implemented a new oil and gas royalty regime effective January 1, 2009 through which the royalties for conventional oil, natural gas and bitumen are linked to price and production levels. The royalty regime applies to both new and existing oil sands projects.

Under the royalty regime, the Government of Alberta increased its royalty share from oil sands development by introducing price-sensitive formulas applied both before and after specified allowed costs have been recovered. Prior to payout of the specified costs, the royalty starts at one percent of gross bitumen revenue and increases for every dollar that the world oil price, as reflected by the WTI crude oil price (converted to Canadian dollars), is above $55 per barrel, to a maximum of nine percent of gross bitumen revenue when the WTI crude oil price is $120 per barrel or higher. After payout, the net royalty on oil sands starts at 25 percent of net bitumen revenue and increases for every dollar the WTI crude oil price (converted to Canadian dollars) is above $55 per barrel to 40 percent of net bitumen revenue when the WTI crude oil price is $120 per barrel or higher.

The Government of Alberta has publicly indicated that it intends for the revised royalty regime to be further reviewed and revised from time to time. There can be no assurances that the Government of Alberta or the Government of Canada will not adopt new royalty regimes which may render the Corporation's projects uneconomic or otherwise adversely affect its business, financial condition or results of operations.

Third Party Risks

Aboriginal peoples have filed certain claims against the Government of Canada, the Province of Alberta and certain governmental entities claiming, among other things, failure of the governments to fulfill their duties to consult and infringement of the aboriginal people's treaty rights.

In particular, on May 14, 2008, the Beaver Lake Cree Nation filed a statement of claim in Alberta Court of Queen's Bench commencing a lawsuit alleging that the Governments of Alberta and Canada have unjustifiably infringed their treaty rights by, among other things, authorizing a range of resource development activities (including the Corporation's development activities) within their traditional lands. On or about June 4, 2008, the Chipewyan Prairie Dene First Nation, or CPDFN, filed a judicial review application in the Alberta Court of Queen's Bench seeking to prevent the Alberta government from granting approvals for Phase 3 of the Christina Lake project because of the alleged failure of Alberta to consult with CPDFN about the effects of Phase 3 on CPDFN's treaty rights. No steps in the CPDFN lawsuit have been taken since it was initiated and MEG has received regulatory authorization to proceed with Phase 3, following approvals issued February 13, 2012 by Alberta Environment and Water and the previous approval on January 31, 2012 by Alberta's Energy Resources Conservation Board.

Such claims and such other similar claims that may be initiated, if successful, could have a significant adverse effect on the Corporation, the Christina Lake project, the Surmont project and the Corporation's future projects.

Disclosure Controls and Procedures

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

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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's internal controls over financial reporting at the financial year end of the Corporation and concluded that the Corporation's internal controls over financial reporting are effective at the financial year end of the Corporation for the foregoing purpose.

No material changes in the Corporation's internal controls over financial reporting were identified during the year ended December 31, 2012 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.

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 or net cash provided by 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, while cash flow from operations is reconciled to net cash provided by operating activities.

Additional Information

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

Quarterly Summaries

	2012					2011				
	FY	Q4	Q3	Q2	Q1	FY	Q4	Q3	Q2	Q1
Financial										
($000 unless specified)										
Net income (loss)	52,569	(18,740)	47,474	(29,534)	53,369	63,837	91,118	(115,196)	42,537	45,378
Per share, diluted	0.26	(0.09)	0.24	(0.15)	0.27	0.32	0.46	(0.60)	0.21	0.23
Operating earnings (loss)	21,242	(538)	(12,883)	11,134	23,529	109,255	57,833	(5,917)	36,474	20,865
Per share, diluted	0.11	0.00	(0.07)	0.06	0.12	0.55	0.29	(0.03)	0.18	0.11
Cash flow from operations	212,514	56,106	24,442	59,975	71,991	304,627	121,608	25,478	88,204	69,337
Per share, diluted	1.06	0.27	0.12	0.30	0.36	1.54	0.61	0.13	0.45	0.35
Capital investment	1,619,683	500,223	406,526	341,840	371,094	984,626	319,897	243,226	209,627	211,876
Cash and short-term investments	2,007,841	2,007,841	1,607,036	1,111,150	1,402,390	1,647,069	1,647,069	1,831,937	1,926,429	2,034,526
Working capital	1,655,915	1,655,915	1,307,325	902,424	1,183,628	1,475,245	1,475,245	1,619,557	1,806,881	1,921,382
Long-term debt	2,488,609	2,488,609	2,461,676	1,751,552	1,718,474	1,751,539	1,751,539	1,791,695	1,660,445	1,673,194
Shareholders' equity	4,870,534	4,870,534	4,092,556	4,027,652	4,049,633	3,984,104	3,984,104	3,879,415	3,983,825	3,921,147
Business Environment										
West Texas Intermediate (WTI) US$/bbl	94.21	88.18	92.22	93.49	102.92	95.12	94.06	89.76	102.56	94.10
C$ equivalent of 1US$ - average	0.9994	0.9913	0.9948	1.0102	1.0012	0.9893	1.0231	0.9802	0.9676	0.9860
Differential – WTI/blend ($/bbl)	29.37	26.13	29.54	29.83	32.10	22.07	17.47	23.53	22.88	27.17
Differential – WTI/blend	31.2%	29.9%	32.2%	31.6%	31.2%	23.5%	18.2%	26.7%	23.1%	29.3%

Quarterly Summaries (continued)

	2012					2011				
	FY	**Q4**	**Q3**	**Q2**	**Q1**	FY	Q4	Q3	Q2	Q1
Operational										
($/bbl unless specified)										
Bitumen production – bpd	28,773	32,292	23,941	30,429	28,446	26,605	30,032	20,945	27,826	27,653
Diluent usage – bpd	12,994	14,810	9,466	13,800	13,919	12,249	14,223	8,229	12,647	14,037
Blend sales – bpd	41,840	47,532	33,342	44,029	42,486	38,836	44,491	28,820	40,507	41,703
Blend sales	64.78	61.29	62.19	64.62	70.95	72.03	78.76	64.46	76.37	65.61
Cost of diluent	(17.85)	(15.62)	(15.70)	(19.03)	(20.80)	(13.29)	(10.77)	(12.67)	(13.59)	(16.04)
Bitumen realization	46.93	45.67	46.49	45.59	50.15	58.74	67.99	51.79	62.78	49.57
Transportation – net	(0.31)	(0.05)	(0.93)	(0.03)	(0.37)	(1.39)	(1.19)	(1.93)	(1.18)	(1.42)
Royalties	(2.46)	(2.23)	(2.10)	(2.84)	(2.63)	(3.24)	(3.66)	(2.82)	(3.69)	(2.64)
Operating costs – non-energy	(9.71)	(8.70)	(15.23)	(7.79)	(8.24)	(10.32)	(8.55)	(17.20)	(8.74)	(8.68)
Operating costs – energy	(3.46)	(4.65)	(3.22)	(2.62)	(3.18)	(5.14)	(4.61)	(5.05)	(5.39)	(5.54)
Power sales	3.19	4.40	2.84	1.86	3.47	4.50	4.66	5.13	2.77	5.59
Cash operating netback	34.18	34.44	27.85	34.17	39.20	**43.15**	**54.64**	**29.92**	**46.55**	**36.88**
Power sales price (C$/MWh)	59.22	79.62	57.99	36.85	58.25	74.33	78.91	93.33	46.95	82.40
Power sales (MW/h)	65	75	49	64	71	67	74	47	68	78
Depletion and depreciation rate	13.76	14.98	13.39	13.01	13.44	12.81	12.60	12.51	12.37	13.71
Common Shares										
Shares outstanding,										
end of period (000)	220,190	220,190	195,248	194,326	193,986	193,472	193,472	192,978	192,767	191,304
Volume traded (000)	73,738	20,370	13,578	21,560	18,230	105,783	16,083	16,706	34,428	38,566
Common share price ($)										
High	47.11	38.74	41.90	43.96	47.11	52.90	48.48	52.90	52.68	50.35
Low	30.25	30.25	35.20	32.92	36.73	32.26	32.26	36.96	46.25	40.90
Close (end of period)	30.44	30.44	37.39	36.49	38.46	41.57	41.57	38.76	50.32	49.06

REPORT OF MANAGEMENT

Management's Responsibility for the Consolidated Financial Statements

The accompanying consolidated financial statements of MEG Energy Corp. (the "Corporation") are the responsibility of Management. The consolidated financial statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and include certain estimates that reflect Management's best judgments. Financial information contained throughout the annual report is consistent with these consolidated financial statements.

The Corporation maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Corporation's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that our internal controls over financial reporting were effective as of December 31, 2012.

The Corporation's Board of Directors has approved the consolidated financial statements. The Board of Directors fulfills its responsibility regarding the consolidated financial statements mainly through its Audit Committee, which is made up of three independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation. The Audit Committee meets with Management and the independent auditors at least on a quarterly basis to review and approve interim consolidated financial statements and management's discussion and analysis prior to their release as well as annually to review the annual consolidated financial statements and management's discussion and analysis and recommend their approval to the Board of Directors.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Corporation's most recent Annual General Meeting, to audit and provide their independent audit opinion on the Corporation's consolidated financial statements as at and for the year ended December 31, 2012. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

W. J. McCaffrey

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

Dale J. Hohm, CA
Chief Financial Officer

February 26, 2013

Independent Auditor's Report

February 26, 2013

To the Shareholders of MEG Energy Corp.

We have audited the accompanying consolidated financial statements of MEG Energy Corp., which comprise the consolidated balance sheet as at December 31, 2012 and December 31, 2011 and the consolidated statement of comprehensive income, consolidated statement of changes in shareholders' equity and consolidated statement of cash flow for the years ended December 31, 2012 and December 31, 2011, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of MEG Energy Corp. as at December 31, 2012 and 2011 and its financial performance and its cash flows for the years ended December 31, 2012 and 2011 in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

FINANCIAL STATEMENTS

Consolidated Balance Sheet

(Expressed in thousands of Canadian dollars)

As at December 31,	Note	2012	2011
Assets			
Current assets			
Cash and cash equivalents	23	$ 1,474,843	$ 1,495,131
Short-term investments		532,998	151,938
Trade receivables and other	7	110,823	135,545
Inventories	8	17,536	9,207
		2,136,200	1,791,821
Non-current assets			
Property, plant and equipment	9	5,267,885	3,368,819
Exploration and evaluation assets	10	554,349	991,805
Other intangible assets	11	46,033	37,292
Other assets	12	14,212	11,312
Total assets		$ 8,018,679	$ 6,201,049
Liabilities			
Current liabilities			
Trade payables	13	$ 463,077	$ 301,626
Current portion of long-term debt	14	9,949	10,145
Current portion of provisions and other liabilities	15	7,259	4,805
		480,285	316,576
Non-current liabilities			
Long-term debt	14	2,478,660	1,741,394
Provisions and other liabilities	15	117,756	91,006
Deferred income tax liability	16	71,444	67,969
Total liabilities		3,148,145	2,216,945
Commitments and contingencies	25		
Subsequent event	28		
Shareholders' equity			
Share capital	17	4,694,378	3,877,193
Contributed surplus	17	102,219	85,568
Retained earnings		73,912	21,343
Accumulated other comprehensive income		25	-
Total shareholders' equity		4,870,534	3,984,104
Total liabilities and shareholders' equity		$ 8,018,679	$ 6,201,049

The accompanying notes are an integral part of these consolidated financial statements.
These consolidated financial statements were approved by the Corporation's Board of Directors on February 26, 2013.

W. J. McCaffrey

William (Bill) McCaffrey, Director

Robert B. Hodgins, Director

Consolidated Statement of Comprehensive Income

(Expressed in thousands of Canadian dollars, except per share amounts)

For the year ended December 31,	Note	2012	2011
Petroleum revenue, net of royalties	18	$ 1,003,838	$ 989,598
Other revenue	19	46,666	47,015
		1,050,504	1,036,613
Diluent and transportation		512,814	467,872
Purchased product and storage		39,584	-
Operating expenses		139,019	150,029
Depletion and depreciation	9, 11	144,950	124,327
General and administrative		70,597	55,738
Stock-based compensation	17	25,246	21,355
Research and development		5,157	6,810
		937,367	826,131
Revenues less operating expenses		113,137	210,482
Other income (expense)			
Interest and other income		19,896	18,786
Gain on disposition of asset		3,075	-
Gain on debt modification		-	2,773
Foreign exchange gain (loss), net		36,618	(35,713)
Net finance expense	20	(110,354)	(86,644)
		(50,765)	(100,798)
Income before income taxes		62,372	109,684
Deferred income tax expense	16	9,803	45,847
Net income		52,569	63,837
Other comprehensive income			
Foreign currency translation adjustment		25	-
Comprehensive income		$ 52,594	$ 63,837
Net earnings per common share			
Basic	24	$ 0.27	$ 0.33
Diluted	24	$ 0.26	$ 0.32

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

Consolidated Statement of Changes in Shareholders' Equity

(Expressed in thousands of Canadian dollars)

	Note	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (AOCI)	Total Shareholders' Equity
Balance as at January 1, 2012		**$ 3,877,193**	**$ 85,568**	**$ 21,343**	**$ -**	**$ 3,984,104**
Shares issued	17	**800,125**				**800,125**
Share issue costs, net of tax	17	**(18,988)**				**(18,988)**
Stock options exercised	17	**26,520**	**(5,863)**			**20,657**
RSU's vested and released	17	**9,528**	**(9,528)**			**-**
Stock-based compensation	17		**32,042**			**32,042**
Net income				**52,569**		**52,569**
Other comprehensive income					**25**	**25**
Balance as at December 31, 2012		**$ 4,694,378**	**$ 102 ,219**	**$ 73,912**	**$ 25**	**$ 4,870,534**
Balance as at January 1, 2011		$ 3,820,446	$ 76,172	$ (42,494)	$ -	$ 3,854,124
Stock options exercised		52,037	(12,320)			39,717
RSU's vested and released		4,710	(4,710)			-
Stock-based compensation			26,426			26,426
Net income				63,837		63,837
Balance as at December 31, 2011		$ 3,877,193	$ 85,568	$ 21,343	$ -	$ 3,984,104

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

Consolidated Statement of Cash Flow

(Expressed in thousands of Canadian dollars)

Year ended December 31,	Note	2012	2011
Cash provided by (used in):			
Operating activities			
Net income		$ 52,569	$ 63,837
Adjustments for:			
Depletion and depreciation	9, 11	144,950	124,327
Stock-based compensation	17	25,246	21,355
Unrealized (gain) loss on foreign exchange		(35,822)	35,207
Unrealized (gain) loss on derivative financial liabilities	20	12,868	(378)
Deferred income tax expense	16	9,803	45,847
Other		2,900	6,009
Net change in non-cash operating working capital items	23	28,310	18,098
Net cash provided by operating activities		240,824	314,302
Investing activities			
Capital investments		(1,598,514)	(928,921)
Proceeds on disposition of assets		7,456	-
Other		1,176	965
Net change in non-cash investing working capital items	23	(230,638)	114,173
Net cash used in investing activities		(1,820,520)	(813,783)
Financing activities			
Issue of shares, net of issue costs		795,466	39,717
Issue of long-term debt, net of issue costs		792,552	1,708,188
Financing costs		(5,622)	(3,025)
Repayment of long-term debt		(9,988)	(986,363)
Net cash provided by financing activities		1,572,408	758,517
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		(13,000)	11,649
Change in cash and cash equivalents		(20,288)	270,685
Cash and cash equivalents, beginning of year	23	1,495,131	1,224,446
Cash and cash equivalents, end of year	23	$ 1,474,843	$ 1,495,131

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Year ended December 31, 2012

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

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

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

3. Significant Accounting Policies

(a) Basis of measurement

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

(b) Basis of consolidation

The consolidated financial statements of the Corporation comprise the Corporation and its wholly-owned subsidiary, MEG Energy (U.S.) Inc., that was incorporated on June 26, 2012. Income and expenses of its subsidiary are included in the consolidated statement of comprehensive income from the date of incorporation.

All intercompany transactions, balances, income and expenses are eliminated on consolidation.

(c) Foreign currency translation

i. Functional and presentation currency

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which the Corporation operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars, which is the Corporation's functional currency.

ii. Transactions and balances

Foreign currency transactions are translated into Canadian dollars at exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in a foreign currency are translated into Canadian dollars at rates of exchange in effect at the end of the period. Foreign currency differences arising on translation are recognized in income or loss.

For the purposes of presenting consolidated financial statements, the assets and liabilities of the foreign subsidiary are translated into Canadian dollars at rates of exchange in effect at the end of the period. Income and expense items are translated at the average exchange rates prevailing at the dates of the transactions. Exchange differences arising, if any, are recognized in other comprehensive income.

(d) Joint venture operations

The Corporation conducts a portion of its exploration, production and pipeline activities with other entities and, accordingly, the accounts reflect only the Corporation's proportionate interest in such activities.

(e) Financial instruments

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Corporation has transferred substantially all risks and rewards of ownership.

Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

At initial recognition, the Corporation classifies its financial instruments in the following categories depending on the purpose for which the instruments were acquired:

i. Financial assets and liabilities at fair value through income or loss

A financial asset or liability is classified in this category if acquired principally for the purpose of selling or repurchasing in the short term. Derivative financial instruments are also included in this category unless they are designated as hedges. The Corporation's other assets are classified as fair value through income or loss.

Financial instruments in this category are recognized initially and subsequently at fair value. Transaction costs are expensed in the consolidated statement of comprehensive income. Gains and losses arising from changes in fair value are presented in income or loss within net finance expense in the period in which they arise. Financial assets and liabilities at fair value through income or loss are classified as current except for any portion expected to be realized or paid beyond twelve months from the balance sheet date.

ii. Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. The Corporation's loans and receivables are comprised of cash and cash equivalents, short-term investments and trade receivables and other, and are included in current assets due to their short-term nature.

Loans and receivables are initially recognized at the amount expected to be received less any required discount to reduce the loans and receivables to fair value. Subsequently, loans and receivables are measured at amortized cost using the effective interest method less any provision for impairment.

iii. Financial liabilities at amortized cost

Financial liabilities at amortized cost include trade payables and long-term debt. Trade payables are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Long-term debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

Financial liabilities are classified as current liabilities if payment is due within twelve months. Otherwise, they are presented as non-current liabilities.

iv. Derivative financial instruments

The Corporation may use derivatives in the form of interest rate swaps and floors to manage risks related to its variable rate debt. All derivatives have been classified at fair value through income or loss. Derivative financial instruments are included on the balance sheet within provisions and other liabilities and are classified as current or non-current based on the contractual terms specific to the instrument.

Gains and losses on re-measurement of derivatives related to finance activities are included in net finance expense in the period in which they arise.

(f) Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held with banks, and other short-term highly liquid investments such as commercial paper, money market deposits or similar instruments, with a maturity of 90 days or less.

(g) Short-term investments

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

(h) Trade receivables and other

Trade receivables are recorded based on the Corporation's revenue recognition policy as described in note 3(r). If applicable, an allowance for doubtful accounts is recorded to provide for specific doubtful receivables. Other amounts include deposits and advances which include funds placed in escrow in accordance with the terms of certain agreements, funds held in trust in accordance with governmental regulatory requirements and funds advanced to joint venture partners.

(i) Inventories

Product inventories consist of crude oil products and are valued at the lower of cost and net realizable value on a weighted average cost basis. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location. Net realizable value is the estimated selling price less applicable selling expenses.

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

i. Recognition and measurement

Exploration and evaluation ("E&E") expenditures, including the costs of acquiring licenses and directly attributable general and administrative costs, initially are capitalized as either tangible or intangible exploration and evaluation assets according to the nature of the assets acquired. The costs are accumulated in cost centres pending determination of technical feasibility and commercial viability. Costs incurred prior to obtaining a legal right or license to explore are expensed in the period in which they are incurred.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units ("CGU's").

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. A review of each project area is carried out, at least annually, to ascertain whether proved or probable reserves have been discovered. Upon determination of proved or probable reserves, intangible exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to a separate category within property, plant and equipment.

Development and production items of property, plant and equipment, which include oil sands development and production assets and pipeline assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development, production and pipeline assets are grouped into CGU's for impairment testing. A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components).

Borrowing costs incurred for the construction of a qualifying asset are capitalized when a substantial period of time is required to complete and prepare the asset for its intended use. All other borrowing costs are recognized over the term of the related debt facility as an expense using the effective interest method. The Corporation capitalizes overhead and administrative expenses that are directly attributable to bringing qualifying assets into operation.

ii. Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil sands and pipeline assets only when it is probable that future economic benefits associated with the item will flow to the Corporation and the cost of the item can be measured reliably. Such capitalized oil sands and pipeline assets generally represent costs incurred in developing proved and/or probable reserves and enhancing production from such reserves. All other expenditures are recognized in income or loss as incurred. The carrying amount of any replaced or sold component is derecognized and any gain or loss is recognized in income or loss.

iii. Depletion and depreciation

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

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

The net carrying value of pipeline transportation equipment is depreciated on a straight-line basis over its estimated fifty year useful life.

Corporate assets consist primarily of office equipment and leasehold improvements and are stated at cost less accumulated depreciation. Depreciation of office equipment is provided over the useful life of the assets on the declining balance basis at 25% per year. Leasehold improvements are depreciated on a straight-line basis over the term of the lease.

(k) Other intangible assets

Other intangible assets acquired by the Corporation which have a finite useful life are carried at cost less accumulated depreciation. Subsequent expenditures are capitalized only to the extent that they increase the future economic benefits embodied in the asset to which they relate. The Corporation incurs costs associated with research and development. Expenditures during the research phase are expensed. Expenditures during the development phase are capitalized only if certain criteria, including technical feasibility and the intent to develop and use the technology, are met. If these criteria are not met, the costs are expensed as incurred. The cost associated with purchasing or creating software which is not an integral part of the related computer hardware is included within other intangible assets. The net carrying value of software is amortized over the useful life of the asset on the declining balance basis at 25% per year.

(l) Leased assets

Leases where the Corporation assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

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

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

When lease inducements are received to enter into operating leases, such inducements are recognized as a deferred liability. The aggregate benefit of inducements is recognized as a reduction of the related lease expense on a straight-line basis, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed.

(m) Impairments

i. Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the fair value or estimated future cash flows of an asset.

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

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

All impairment losses are recognized in income or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in income or loss.

ii. Non-financial assets

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

For the purpose of impairment testing, assets are grouped into CGU's. 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. E&E assets are assessed for impairment within the aggregation of all CGU's in that segment.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

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 in income or loss. Impairment losses recognized in respect of CGU's are allocated to reduce the carrying amounts of the assets in the CGU on a pro rata basis.

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

(n) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

The Corporation's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

The decommissioning provision is measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the decommissioning provision is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation as well as any changes in the discount rate. Increases in the decommissioning provision due to the passage of time are recognized as a finance expense whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the obligations are charged against the decommissioning provision.

(o) Deferred income taxes

Deferred income tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted as at the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(p) Share capital

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

(q) Share based payments

The grant date fair value of stock options and restricted share units ("RSUs") granted to employees, directors and consultants is recognized as stock-based compensation expense, with a corresponding increase in contributed surplus, over the vesting period of the options and RSUs respectively. Each tranche in an award is considered a separate grant with its own vesting period and grant date fair value. Fair value is determined using the Black-Scholes option pricing model. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options and RSUs that vest. The Corporation's RSU Plan allows the holder of an RSU to receive a cash payment or its equivalent in fully-paid common shares, at the Corporation's discretion, equal to the fair market value of the Corporation's common shares calculated at the date of such payment. The Corporation does not intend to make cash payments under the RSU Plan and, as such, the RSUs are accounted for within shareholders' equity.

(r) Revenues

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

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

(s) Diluent and transportation

Diluent and transportation include diluent costs and the cost of operating the Access Pipeline and are recognized as the related product is utilized.

(t) Purchased product and storage

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

(u) Net finance expense

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

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

(v) Net earnings per share

Basic earnings per share is calculated by dividing the net income (loss) for the period attributable to common shareholders of the Corporation by the weighted average number of common shares outstanding during the period.

Diluted earnings per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to options, RSUs and other similar instruments is computed using the treasury stock method. The Corporation's potentially dilutive instruments comprise stock options and RSUs granted to employees and directors.

(w) Accounting standards issued but not yet applied

The IASB has issued the following standards which have not yet been adopted by the Corporation: IFRS 9, Financial Instruments; IFRS 10, Consolidated Financial Statements; IFRS 11, Joint Arrangements; IFRS 12, Disclosure of Interests in Other Entities; and IFRS 13, Fair Value Measurement. Also, the IASB has amended the following standards which have not yet been adopted by the Corporation: IAS 1, Presentation of Financial Statements; IAS 19, Employee Benefits; IAS 27 Separate Financial Statements; IAS 28, Investments in Associates and Joint Ventures; IAS 32, Financial Instruments: Presentation; and IFRS 7, Financial Instruments: Disclosure. The new standards, except IFRS 9 and the amendments to IAS 32, are effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. The effective date of IFRS 9 is for annual periods beginning on or after January 1, 2015 with early adoption permitted. The amendments to IAS 1 are effective for periods beginning on or after July 1, 2012. The amendments to IAS 32 are effective for periods beginning on or after January 1, 2014. The Corporation has performed an initial assessment of the impact of the new and amended standards and does not currently expect that the adoption of these standards will have a significant impact on the Corporation's consolidated financial statements.

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

IFRS 9 is the first step to replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IFRS 10 replaces SIC-12, Consolidation—Special Purpose Entities, and parts of IAS 27, Consolidated and Separate Financial Statements.

IFRS 11 requires an entity to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting, whereas for a joint operation, the entity will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures. IFRS 11 supersedes IAS 31, Interests in Joint Ventures, and SIC-13, Jointly Controlled Entities—Non-monetary Contributions by Venturers.

IFRS 12 establishes disclosure requirements for interests in other entities, such as joint arrangements, associates, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interests in other entities.

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosures about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurements and in many cases does not reflect a clear measurement basis or consistent disclosures.

IAS 1 Presentation of Financial Statements was amended in June 2011 to require entities to group separately within other comprehensive income those items which may be subsequently reclassified to profit or loss from those that will not and to require the tax associated with items presented before tax to be shown separately for each of the two groups. The amendments to IAS 1 are applicable to annual periods beginning on or after July 1, 2012.

IAS 19 has been amended to 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. A number of other amendments have been made to recognition, measurement and classification including redefining short-term and other long-term benefits, guidance on the treatment of taxes related to benefit plans, guidance on risk/cost sharing features, and expanded disclosures.

IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 – 13. IFRS 7 and IAS 32 were amended to clarify the requirements for the offsetting of financial assets and financial liabilities on the balance sheet and to enhance the disclosure requirements pertaining to the offsetting of financial assets and financial liabilities on the balance sheet.

4. Significant Accounting Estimates, Assumptions and Judgements

The timely preparation of the consolidated financial statements requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ materially from estimated amounts as future confirming events occur. Significant judgments, estimates and assumptions made by management in the preparation of these consolidated financial statements are outlined below.

(a) Property, plant and equipment

Field production assets within property, plant and equipment are depleted using the unit of production method based on estimates of proved bitumen reserves and future costs required to develop those reserves. There are a number of inherent uncertainties associated with estimating reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

In addition, management is required to make estimates and assumptions and use judgment regarding the timing of when major development projects are ready for their planned use, which also determines when these assets are subject to depreciation and depletion.

Amounts recorded for depreciation of major facilities and equipment and pipeline transportation equipment are based on management's best estimate of their useful lives. Accordingly, those amounts are subject to measurement uncertainty.

(b) Exploration and evaluation assets

The application of the Corporation's accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined and when technical feasibility and commercial viability have been reached. Estimates and assumptions may change as new information becomes available.

(c) Bitumen reserves

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

(d) Decommissioning provision

Decommissioning costs are incurred when certain of the Corporation's tangible long-lived assets are retired. Assumptions, based on current economic factors which management believes are reasonable, have been made to estimate the future liability. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. The impact to net income over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. In addition, management exercises judgment to determine the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

(e) Impairments

CGU's are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGU's requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures, and the way in which management monitors the Corporation's operations.

The recoverable amounts of CGU's and individual assets have been determined as the higher of the CGU's or the asset's fair value less costs to sell and its value in use. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGU's.

(f) Stock-based compensation

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

(g) Deferred income taxes

Tax regulations and legislation and the interpretations thereof in which the Corporation operates are subject to change. As such, income taxes are subject to measurement uncertainty.

Deferred income tax liabilities are recognized when there are taxable temporary differences that will reverse and result in a future outflow of funds to a taxation authority. The Corporation records a provision for the amount that is expected to be settled, which requires the application of judgment as to the ultimate outcome. Deferred income tax liabilities could be impacted by changes in the Corporation's estimate of the likelihood of a future outflow and the expected settlement amount. As such, there may be a significant impact on the consolidated financial statements of future periods.

Deferred income tax assets are recognized to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the consolidated financial statements of future periods.

(h) Derivative financial instruments

The estimated fair values of financial assets and liabilities, by their very nature, are subject to measurement uncertainty due to their exposure to credit, liquidity and market risks. Furthermore, the Corporation may use derivative instruments to manage commodity price, foreign currency and interest rate exposures. The fair values of these derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and as such are subject to measurement uncertainty.

5. Determination of Fair Value

A number of the Corporation's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

i. Cash and cash equivalents, short-term investments, trade receivables and other and trade payables:

The fair values of cash and cash equivalents, short-term investments, trade receivables and other and trade payables are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2012 and 2011, the carrying value approximates the fair value of the respective assets and liabilities due to the short term nature of the instruments.

ii. Other assets:

Other assets are comprised of investments in asset-backed commercial paper that were restructured into Master Asset Vehicle ("MAV") notes, US auction rate securities ("ARS") and prepaid financing costs. 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.

iii. Derivative financial liabilities and long-term debt:

The fair value of derivative financial liabilities are derived using third party valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates for the Corporation's interest rate swaps and floors. Management's assumptions rely on external observable market data including interest rate yield curves and foreign exchange rates. The fair value of long-term debt is derived from quoted prices from financial institutions.

iv. Share-based payments:

The fair value of stock options and restricted share units granted to employees and directors are measured using a Black-Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility, weighted average expected life of the instruments, forfeiture rate, and the risk-free interest rate (based on government bonds).

There were no significant events affecting the fair value of the Corporation's financial instruments or transfers of financial instruments between levels of the fair value hierarchy during the period.

6. 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, trade payables, derivative financial liabilities and long-term debt. As at December 31, 2012, 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 trade payables were classified as other financial liabilities. Long-term debt was carried at amortized cost.

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

			Fair value measurements using		
As at December 31, 2012	**Carrying amount**	**Fair value**	**Quoted prices in active markets (Level 1)**	**Significant other observe inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
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**	**-**	**-**

			Fair value measurements using		
As at December 31, 2011	Carrying amount	Fair value	Quoted prices in active markets (Level 1)	Significant other observe inputs (Level 2)	Significant unobservable inputs (Level 3)
Financial assets					
Other assets	$ 7,554	$ 7,554	$ -	$ -	$ 7,554
Financial liabilities					
Derivative financial liabilities	24,326	24,326	-	24,326	-
Long-term debt	1,751,539	1,789,926	1,789,926	-	-

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. The Corporation estimated the fair value of the MAV notes and the auction rate securities 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.

Movement in level 3 instruments during the year:

	MAV Notes	ARS	Total
Balance as at December 31, 2011	$ 4,707	$ 2,847	$ 7,554
Increase (decrease) in fair value	3,201	(683)	2,518
Proceeds received	(1,404)	-	(1,404)
Foreign exchange	-	(58)	(58)
Less current portion	(1,029)	-	(1,029)
Balance as at December 31, 2012	**$ 5,475**	**$ 2,106**	**$ 7,581**

(b) Interest rate risk

Interest rate risk arises from changes in market interest rates that may affect earnings, cash flows and valuations. The Corporation has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

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$987.5 million senior secured term loan. At December 31, 2012, there was an unrealized loss on the interest rate swaps of $12.4 million (December 31, 2011 – $2.5 million).

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

[1] London Interbank Offered Rate

As at December 31, 2012, a 100 basis points increase in LIBOR on floating rate debt, excluding the impact of interest capitalized, would have resulted in a $5.6 million decrease in net income before income taxes (December 31, 2011 - $4.0 million). As at December 31, 2012, a 100 basis points decrease in LIBOR, excluding the impact of interest capitalized, would have had no impact on net income before income taxes (December 31, 2011 - $nil).

(c) Foreign currency risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the fair value or future cash flows of the Corporation's financial assets or liabilities. The Corporation has US dollar denominated long-term debt as described in note 14. As at December 31, 2012, a US$0.01 change in the US dollar relative to the Canadian dollar exchange rate would have resulted in a corresponding change in the carrying value of long-term debt of US$25.4 million (December 31, 2011 - US$17.5 million).

(d) Commodity price risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. The Corporation's financial results may be significantly impacted by factors outside of the Corporation's control, including commodity prices and heavy oil differentials. Future fluctuations in commodity prices will affect the amount of revenue earned by the Corporation on the sale of its bitumen production and will impact the amount the Corporation pays for natural gas, electricity and diluent, which are all inputs into the steam-assisted gravity drainage ("SAGD") production and transportation process.

Surplus power from the Corporation's cogeneration unit is sold into the Alberta power grid to partially offset natural gas and power costs associated with operations, acting as a partial hedge against fuel price changes.

(e) Credit risk

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty to a financial instrument fails to meet its obligations in accordance with agreed terms. This credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. Agreements are entered into with major financial institutions with investment grade credit ratings. A substantial portion of accounts receivable are with customers in the petroleum and natural gas industry and are subject to normal industry credit risk. At December 31, 2012, the Corporation's estimated maximum exposure to credit risk related to customers was $104.0 million. There were no significant amounts which were greater than 90 days as at December 31, 2012.

The Corporation's cash balances are used to fund the development of its oil sands properties. As a result, the primary objectives of the investment portfolio are low risk capital preservation and high liquidity. The cash balances are invested in high grade liquid short term debt such as commercial, government and bank paper. The cash, cash equivalents and short-term investments balance at December 31, 2012 was $2.0 billion. None of the investments are past their maturity or considered impaired. The Corporation's estimated maximum exposure to credit risk related to its cash, cash equivalents and short-term investments is $2.0 billion.

The Corporation's investments in MAV Notes and ARS are subject to the credit risk associated with the counterparties to the investments. The Corporation's estimated maximum exposure to credit risk related to its investments in MAV Notes and ARS is $7.6 million.

(f) Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk that the Corporation cannot earn enough income from the Christina Lake Project or is unable to raise further capital in order to meet its debt service obligations. The lenders are entitled to exercise any and all remedies available under the security documents. The Corporation manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit.

The future undiscounted financial obligations of the Corporation are noted below:

As at December 31, 2012	**Total**	**< 1 year**	**1 – 3 years**	**4 – 5 years**	**More than 5 years**
Long-term debt	$ 2,524,559	$ 9,949	$ 19,898	$ 19,898	$ 2,474,814
Interest on long-term debt	1,109,044	138,391	275,587	273,995	421,071
Derivative financial liabilities	37,195	11,044	18,492	7,659	-
Trade payables	463,077	463,077	-	-	-
	$ 4,133,875	**$ 622,461**	**$ 313,977**	**$ 301,552**	**$ 2,895,885**

As at December 31, 2011	Total	< 1 year	1 – 3 years	4 – 5 years	More than 5 years
Long-term debt	$ 1,777,208	$ 10,145	$ 20,290	$ 20,290	$ 1,726,483
Interest on long-term debt	701,607	90,157	179,094	177,467	254,889
Derivative financial liabilities	24,326	4,056	14,858	3,173	2,239
Trade payables	301,626	301,626	-	-	-
	$ 2,804,767	$ 405,984	$ 214,242	$ 200,930	$ 1,983,611

7. Trade Receivables and Other

As at December 31,	2012	2011
Trade receivables	**$ 104,008**	$ 124,341
Deposits and advances	**4,757**	10,034
Current portion of deferred financing costs	**2,058**	1,170
	$ 110,823	$ 135,545

8. Inventories

As at December 31,	2012	2011
Diluent	**$ 14,778**	$ 7,078
Bitumen blend	**1,948**	1,107
Materials and supplies	**810**	1,022
	$ 17,536	$ 9,207

During the year ended December 31, 2012, a total of $496.6 million (2011 - $451.0 million) in inventory product costs were charged to earnings through diluent and transportation.

9. Property, Plant and Equipment

	Crude oil	Corporate assets	Total
Cost			
Balance as at December 31, 2010	$ 2,647,682	$ 16,868	$ 2,664,550
Additions	915,615	10,742	926,357
Disposals	(5,540)	-	(5,540)
Balance as at December 31, 2011	$ 3,557,757	$ 27,610	$ 3,585,367
Additions	1,563,502	5,987	1,569,489
Disposals	(6,340)	-	(6,340)
Transfer from exploration and evaluation assets (note 10)	478,347	-	478,347
Balance as at December 31, 2012	**$ 5,593,266**	**$ 33,597**	**$ 5,626,863**
Accumulated depletion and depreciation			
Balance as at December 31, 2010	$ 96,906	$ 1,170	$ 98,076
Depletion and depreciation	121,861	2,151	124,012
Disposals	(5,540)	-	(5,540)
Balance as at December 31, 2011	$ 213,227	$ 3,321	$ 216,548
Depletion and depreciation	141,118	3,270	144,388
Disposals	(1,958)	-	(1,958)
Balance as at December 31, 2012	**$ 352,387**	**$ 6,591**	**$ 358,978**
Carrying Amounts			
As at December 31, 2011	$ 3,344,530	$ 24,289	$ 3,368,819
As at December 31, 2012	**$ 5,240,879**	**$ 27,006**	**$ 5,267,885**

During the year ended December 31, 2012 the Corporation capitalized $20.9 million (year ended December 31, 2011 - $14.1 million) of general and administrative expenses and $6.8 million (year ended December 31, 2010 - $5.1 million) of stock-based compensation costs relating to oil sands exploration and development activities. In addition, $30.6 million of interest and finance charges related to the development of growth capital projects were capitalized during the year ended December 31, 2012 utilizing a weighted average capitalization rate of 6.7% (year ended December 31, 2011 - $14.6 million; weighted average capitalization rate – 4.6%).

The Corporation transports its bitumen blend volumes and diluents purchases on pipelines that are operated by Access Pipeline. The Corporation has an undivided 50% interest in this jointly controlled entity and accounts for its investment using the proportionate consolidation method. As at December 31, 2012, the Corporation's proportionate interest in the joint venture's related pipeline assets was $543.2 million, which have been included in property, plant and equipment (December 31, 2011 - $405.5 million).

Operating commitments of $7.2 million related to the joint venture are included in "Other commitments" presented within Note 25.

10. Exploration and Evaluation Assets

Cost	
Balance as at December 31, 2010	$ 937,986
Additions	53,819
Balance as at December 31, 2011	$ 991,805
Additions	40,891
Transfer to property, plant and equipment (note 9)	(478,347)
Balance as at December 31, 2012	**$ 554,349**

Exploration and evaluation assets were transferred to property, plant and equipment 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 December 31, 2012, no impairment has been recognized on these assets.

11. Other Intangible Assets

Cost	
Balance as at December 31, 2010	$ 33,738
Additions	4,448
Balance as at December 31, 2011	$ 38,186
Additions	9,303
Balance as at December 31, 2012	**$ 47,489**
Accumulated depreciation	
Balance as at December 31, 2010	$ 580
Depreciation	314
Balance as at December 31, 2011	$ 894
Depreciation	562
Balance as at December 31, 2012	**$ 1,456**
Carrying Amounts	
As at December 31, 2011	$ 37,292
As at December 31, 2012	**$ 46,033**

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.

12. Other Assets

As at December 31,	2012	2011
MAV Notes[a]	$ 5,475	$ 4,707
ARS[b]	2,106	2,847
Prepaid financing costs[c]	8,689	4,928
	16,270	12,482
Less current portion of prepaid financing costs	(2,058)	(1,170)
	$ 14,212	$ 11,312

(a) The Corporation's investment of $8.1 million in MAV Notes that mature between 2014 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 the statement of comprehensive income in the period in which they arise. As at December 31, 2012, the total impairment provision on the notes was $2.6 million (2011 - $7.6 million).

(b) The US$3.2 million 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 regarding the timing of payments and credit rating of the securities.

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

13. Trade Payables

As at December 31,	2012	2011
Trade payables	$ 51,651	$ 26,939
Accruals	370,431	256,215
Interest payable	36,848	14,674
Other payables	4,147	3,798
	$ 463,077	$ 301,626

14. Long-Term Debt

As at December 31,	2012	2011
Senior secured term loan (December 31, 2012 - US$987.5 million; December 31, 2011 - US$997.5 million)[a]	$ 982,464	$ 1,014,458
6.5% senior unsecured notes (December 31, 2012 and 2011 US$750 million)[b]	746,175	762,750
6.375% senior unsecured notes (December 31, 2012 US $800 million; December 31, 2011 - nil)[c]	795,920	-
	2,524,559	1,777,208
Less current portion of senior secured term loan	(9,949)	(10,145)
Less unamortized financial derivative liability discount	(10,324)	(12,130)
Less unamortized deferred debt issue costs	(25,626)	(13,539)
	$ 2,478,660	$ 1,741,394

The US dollar denominated debt was translated into Canadian dollars at the year-end exchange rate of US$1 = C$0.9949 (December 31, 2011 – US$1 = C$1.017).

There are no financial debt covenants as at December 31, 2012 and 2011.

(a) The senior secured credit facilities are comprised of a US$987.5 million term loan and a five year US$1.0 billion revolving credit facility. The US$987.5 million 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 200 or 300 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 0.25% of the original outstanding balance beginning on December 31, 2011, with the balance due on March 18, 2018. Interest is paid quarterly. All of the Corporation's assets, except for its interest in the Access Pipeline and certain undeveloped properties, have been pledged as collateral on the senior secured term loan.

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 December 31, 2012, $2.6 million (December 31, 2011 - $0.8 million) of the revolving credit facility was utilized to support letters of credit. As at December 31, 2012, 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 debt issue costs of $12.2 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 $13.4 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

	2013	2014	2015	2016	2017	Thereafter
Required debt principal repayments	$ 9,949	$ 9,949	$ 9,949	$ 9,949	$ 9,949	$ 2,474,814

15. Provisions and Other Liabilities

As at December 31,	2012	2011
Derivative financial liabilities[a]	$ 37,195	$ 24,326
Decommissioning provision[b]	82,087	65,360
Deferred lease inducements[c]	5,733	6,125
Provisions and other liabilities	125,015	95,811
Less current portion of derivative financial liabilities	(6,509)	(4,056)
Less current portion of deferred lease inducements	(750)	(749)
Non-current portion of provisions and other liabilities	$ 117,756	$ 91,006

(a) Derivative financial liabilities

The Corporation's term loan D, which was subsequently replaced with the March 18, 2011 amendment of the senior secured credit facility (see Note 14), carried an interest rate floor of 300 basis points based on US prime and an interest rate floor of 200 basis points based on LIBOR. This interest rate floor was considered an embedded derivative under IFRS 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 was required to be separated from the carrying value of long-term debt and accounted for as a separate financial liability measured at fair value through income or loss.

On March 18, 2011 the senior secured credit facility was amended, which required the $37.2 million fair value of the 2% floor derivative financial liability to be derecognized through gain on debt modification. The amended senior secured credit facility carries an interest rate floor of 200 basis points based on US prime and an interest rate floor of 100 basis points based on LIBOR. This interest rate floor is considered 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 financial liability measured at fair value through income or loss.

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 in order to manage its floating to fixed interest rate mix on long-term debt. As of December 31, 2012, the Corporation has entered into interest rate swaps on US$748.0 million and these interest rate swap contracts expire on September 30, 2016 (see Note 6(b)). 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.

The following table summarizes the change in the derivative financial liability:

As at December 31,	2012	2011
Derivative financial liability, beginning of year	$ 24,326	$ 37,302
Write-off of embedded derivative – 2% interest floor on debt amendment	-	(37,302)
Embedded derivative recognized on 1% interest floor	-	13,507
Increase in fair value of embedded derivative on 1% interest floor	2,953	8,346
Increase in interest rate swap liability fair value	9,916	2,473
Derivative financial liabilities, end of year	37,195	24,326
Less current portion of derivative financial liabilities	(6,509)	(4,056)
Non-current portion of derivative financial liabilities	$ 30,686	$ 20,270

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

As at December 31,	2012	2011
Decommissioning provision, beginning of year	$ 65,360	$ 12,557
Changes in estimated future cash flows	-	24,876
Changes in discount rates	(3,846)	-
Liabilities acquired	-	1,522
Liabilities incurred	18,218	25,471
Liabilities settled	(1,315)	(712)
Accretion	3,670	1,646
Decommissioning provision, end of year	$ 82,087	$ 65,360

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 $82.1 million as at December 31, 2012 (December 31, 2011 - $65.4 million) based on an undiscounted total future liability of $228.1 million (December 31, 2011 - $179.1 million) and a credit-adjusted rate of 5.7% (December 31, 2011 – 5.4%). This obligation is estimated to be settled in periods up to 2057.

As at December 31, 2012, a 1% increase in the credit-adjusted discount rate would result in a $14.7 million decrease in the present value of the decommissioning provision.

In the fourth quarter of 2011, the Corporation changed its accounting policy from using a risk-free rate, to a credit-adjusted rate to calculate the discounted value of the estimated future cash outflows required to settle the decommissioning obligation. The change was applied retrospectively, and on the transition to IFRS at January 1, 2010, resulted in a $3.9 million decrease to the decommissioning provision and a $2.9 million decrease in the deficit, net of $1.0 million in deferred taxes (December 31, 2010 - $10.6 million decrease to the decommissioning provision, $7.9 million decrease in the deficit, net of $2.7 million in deferred taxes).

(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.

16. Deferred Income Taxes

The deferred tax provisions differ from results which would be obtained had the Corporation applied the combined federal and provincial statutory rates of 25% (2011 – 26.5%) to earnings. The reasons for these differences are as follows:

For the years ended December 31,	2012	2011
Expected income tax expense	$ 15,593	$ 29,066
Add (deduct) the effect of:		
Stock-based compensation	6,312	5,659
Non-taxable (gain) loss on foreign exchange	(6,103)	6,197
Taxable capital losses (recognized) not recognized	(6,121)	7,548
Other	122	(2,623)
	$ 9,803	$ 45,847

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

As at December 31,	2012	2011
Deferred tax liabilities:		
Deferred tax liabilities to be recovered after more than 12 months	$ 542,075	$ 452,769
Deferred tax liabilities to be recovered within 12 months	-	25,427
	542,075	478,196
Deferred tax assets:		
Deferred tax assets to be recovered after more than 12 months	(461,958)	(393,619)
Deferred tax assets to be recovered within 12 months	(8,673)	(16,608)
	(470,631)	(410,227)
Deferred tax liabilities (net)	$ 71,444	$ 67,969

The gross movement on the deferred income tax account is as follows:

	2012	2011
Balance as at January 1	$ 67,969	$ 23,363
Income statement charge	9,803	45,847
Other	-	(1,241)
Tax credited directly to equity[1]	(6,328)	-
Balance as at December 31	$ 71,444	$ 67,969

[1] Deferred tax asset resulting from share issue costs incurred for the December 2012 equity issuance (note 17(b)).

The movement in deferred income tax assets and liabilities during the year is as follows:

Deferred tax liabilities	Property, plant and equipment	Provisions	Other	Total
Balance as at January 1, 2011	$ 434,840	$ -	$ 6,837	$ 441,677
Charged (credited) to the income statement	43,701	240	(6,181)	37,760
Other	(1,241)	-	-	(1,241)
As at December 31, 2011	477,300	240	656	478,196
Charged (credited) to the income statement	64,775	(240)	(656)	63,879
Balance as at December 31, 2012	**$ 542,075**	**$ -**	**$ -**	**$ 542,075**

Deferred tax assets	Tax losses	Derivative financial liabilities	Provisions	Other	Total
Balance as at January 1, 2011	$ (396,691)	$ (9,326)	$ -	$ (12,297)	$ (418,314)
Charged to the income statement	1,636	3,245	-	3,206	8,087
As at December 31, 2011	(395,055)	(6,081)	-	(9,091)	(410,227)
Charged (credited) to the income statement	(56,148)	(3,217)	(349)	5,638	(54,076)
Credited to equity	-	-	-	(6,328)	(6,328)
Balance as at December 31, 2012	**$(451,203)**	**$ (9,298)**	**$ (349)**	**$ (9,781)**	**$ (470,631)**

As at December 31, 2012, the Corporation had approximately $3.6 billion in available tax pools (December 31, 2011 - $3.1 billion). Included in the tax pools are $1.8 billion of non-capital loss carry forward balances ($212.6 million expiring in 2026; $253.9 million expiring in 2027; $341.4 million expiring in 2028; $528.7 million expiring in 2029; and $467.8 million expiring after 2029). In addition, as at December 31, 2012, the Corporation had an additional $1.8 billion (December 31, 2011 - $887.8 million) of capital investment in incomplete projects which will serve to increase available tax pools upon completion of the projects.

17. Share Capital

(a) Authorized:

Unlimited number of common shares

Unlimited number of preferred shares

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

	2012		2011	
	Number of shares	**Amount**	Number of shares	Amount
Balance, beginning of year	**193,471,705**	**$ 3,877,193**	189,875,151	$ 3,820,446
Shares issued	**24,246,212**	**800,125**	-	-
Share issue costs, net of tax	**-**	**(18,988)**	-	-
Issued upon exercise of stock options	**2,243,319**	**26,520**	3,462,840	52,037
Issued upon vesting and release of RSUs	**228,848**	**9,528**	133,714	4,710
Balance, end of year	**220,190,084**	**$ 4,694,378**	193,471,705	$ 3,877,193

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. A total of 12,125,000 common shares were issued through a public bought deal financing while the remaining 12,121,212 common shares were issued on a private placement basis.

(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.

	2012		2011	
	Stock options	**Weighted average exercise price per share**	Stock options	Weighted average exercise price per share
Outstanding, beginning of year	**10,190,103**	**$27.12**	12,919,846	$21.51
Granted	**1,456,537**	**35.67**	810,682	50.52
Exercised	**(2,243,319)**	**9.21**	(3,462,840)	11.47
Forfeited	**(255,917)**	**40.29**	(77,585)	37.41
Outstanding, end of year	**9,147,404**	**$32.50**	10,190,103	$27.12

	Outstanding			Vested		
Range of exercise prices	Options	Weighted average exercise price	Weighted average remaining life (in years)	Options	Weighted average exercise price	Weighted average remaining life (in years)
$2.15 - $19.99	1,014,935	$ 7.62	0.11	1,014,935	$ 7.62	0.11
$20.00 - $29.99	2,320,260	25.03	2.71	2,301,760	25.04	2.70
$30.00 - $39.99	2,307,335	34.95	5.71	627,796	34.15	4.52
$40.00 - $49.99	2,865,976	41.17	2.11	2,745,453	41.04	1.96
$50.00 - $51.43	638,898	51.42	5.43	217,757	51.42	5.43
	9,147,404	$32.50	3.18	6,907,701	$ 30.50	2.28

The fair value of each option granted during the year ended December 31, 2012 and 2011 is estimated on the date of the grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2012	2011
Risk free rate	**1.30%**	2.19%
Expected lives	**5 years**	5 years
Volatility	**40%**	40%
Annual dividend per share	**$ nil**	$ nil
Fair value of options granted	**$ 14.65**	$ 19.26

(d) Restricted share units outstanding:

The RSU Plan allows for the granting of RSUs to directors, officers or 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.

	2012	2011
	RSUs	RSUs
Outstanding, beginning of year	554,362	404,945
Granted	664,796	301,273
Vested and released	(228,848)	(133,714)
Forfeited	(36,506)	(18,142)
Outstanding, end of year	953,804	554,362

(e) Contributed surplus:

	2012	2011
Balance, beginning of year	$ 85,568	$ 76,172
Stock-based compensation - expensed	25,246	21,356
Stock-based compensation - capitalized	6,796	5,070
Stock options exercised	(5,863)	(12,320)
RSUs vested and released	(9,528)	(4,710)
Balance, end of year	$ 102,219	$ 85,568

18. Petroleum Revenue, Net of Royalties

For the years ended December 31,	2012	2011
Petroleum sales:		
Proprietary	$ 991,975	$ 1,021,036
Third party	37,822	-
	1,029,797	1,021,036
Royalties	(25,959)	(31,438)
Petroleum revenue, net of royalties	$ 1,003,838	$ 989,598

19. Other Revenue

For the years ended December 31,	2012	2011
Power revenue	$ 33,634	$ 43,628
Transportation revenue	13,032	3,387
Other revenue	$ 46,666	$ 47,015

20. Net Finance Expense

For the years ended December 31,	2012	2011
Total interest expense	$ 122,424	$ 88,276
Less capitalized interest	30,608	14,629
Net interest expense	91,816	73,647
Accretion on decommissioning provision	3,670	1,646
Unrealized fair value loss on embedded derivative financial liabilities	2,953	8,346
Unrealized fair value loss on interest rate swaps	9,915	2,473
Realized loss on interest rate swaps	4,518	532
Unrealized fair value gain on other assets	(2,518)	-
Net finance expense	$ 110,354	$ 86,644

21. Wages and Employee Benefits Expense

For the years ended December 31,	2012	2011
Operating expense:		
Salaries and wages	$ 32,618	$ 27,804
Short-term employee benefits	2,778	2,096
General and administrative expense:		
Salaries and wages	52,307	39,891
Short-term employee benefits	6,086	4,381
	$ 93,789	$ 74,172

22. Compensation of Key Management Personnel

Key management personnel are comprised of the Corporation's directors and executive officers and their compensation is as follows:

For the years ended December 31,	2012	2011
Salaries and short-term employee benefits	$ 8,489	$ 7,254
Share-based compensation expense	9,885	8,015
	$18,374	$15,269

23. Supplemental Cash Flow Disclosures

As at December 31,	2012	2011
Cash provided by (used in):		
Change in non-cash working capital items:		
Short-term investments	$ (381,060)	$ 15,468
Trade receivables and other	25,610	(37,411)
Inventories	(8,329)	(3,034)
Trade payables	161,451	157,248
	$ (202,328)	$ 132,271
Changes in non-cash working capital relating to:		
Operations	$ 28,310	$ 18,098
Investing	(230,638)	114,173
	$ (202,328)	$ 132,271
Cash and cash equivalents:		
Cash	$ 224,241	$ 29,519
Cash equivalents	1,250,602	1,465,612
	$ 1,474,843	$ 1,495,131
Cash interest paid	$ 88,820	$ 66,554
Cash interest received	$ 19,896	$ 18,786

24. Net Earnings Per Common Share

For the years ended December 31,	2012	2011
Net income	$ 52,569	$ 63,837
Weighted average common shares outstanding	196,667,540	192,298,562
Dilutive effect of stock options and restricted share units	3,294,847	5,475,942
Weighted average common shares outstanding – diluted	199,962,387	197,774,504
Net earnings per common share, basic	$ 0.27	$ 0.33
Net earnings per common share, diluted	$ 0.26	$ 0.32

25. Commitments and Contingencies

(a) Commitments

The Corporation had the following commitments as at December 31, 2012.

Operating:

	2013	2014	2015	2016	2017	Thereafter
Office lease rentals	$ 10,986	$ 10,986	$11,159	$11,554	$11,554	$ 67,231
Diluent purchases	405,202	33,055	-	-	-	-
Pipeline transportation	984	30,905	30,413	60,992	60,826	1,217,514
Other commitments	25,836	34,386	19,592	7,420	6,525	36,141
Annual commitments	$443,008	$109,332	$61,164	$79,966	$78,905	$1,320,886

Capital:

As part of normal operations, the Corporation has entered into a total of $491.9 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.

26. Capital Disclosures

The Corporation considers capital at December 31, 2012 to include cash and cash equivalents of $1,474.8 million (December 31, 2011 - $1,495.1 million), short-term investments of $533.0 million (December 31, 2011 - $151.9 million), long-term debt of $2,524.6 million (December 31, 2011 - $1,777.2 million) and shareholders' equity of $4,870.5 million (December 31, 2011 - $3,984.1 million). As at December 31, 2012, the Corporation's capital resources also included an additional undrawn US$1.0 billion revolving credit facility.

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.

27. Comparative Figures

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

28. Subsequent Event

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 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 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.

Directors and Officers

Board of Directors

Boyd Anderson [1][3]
Lead Director, independent

Harvey Doerr [3]
Governance and Nominating Committee Chair, independent

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

Peter R. Kagan [2][3]
independent

David B. Krieger [1]
independent

William (Bill) McCaffrey
Chairman, President and Chief Executive Officer, non-independent

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

David J. Wizinsky
Corporate Secretary, non-independent

Li Zheng
independent

Detailed biographies of MEG's Board of Directors are available on the corporation's website at **www.megenergy.com**

[1] Audit Committee
[2] Compensation Committee
[3] Governance and Nominating Committee

Corporate Officers

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

Dale Hohm
Chief Financial Officer

Grant Boyd
Senior Vice President, Resource Management – Growth Properties

Stephen Diotte
Vice President, Human Resources, IT and Corporate Services

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

Don Moe
Vice President, Supply and Marketing

John Rogers
Vice President, Investor Relations and External Communications

Richard Sendall
Senior Vice President, Strategy and Government Relations

Ted Semadeni
General Counsel

Chris Sloof
Vice President, Projects

Don Sutherland
Vice President, Regulatory and Community Relations

Chi-Tak Yee
Senior Vice President, Reservoir and Geosciences

The Honourable Peter Lougheed, former Premier of Alberta and member of MEG's Board of Directors since 2005 passed away in September of 2012. He brought to our Board his broad experience, integrity and a commitment to responsible resource development that has helped guide our business and our values as a corporation.

Li Zheng, former president of CNOOC Canada Ltd., is stepping down from MEG's Board Directors after three years since first being elected in 2010. Mr. Zheng has been a strong supporter of a carefully planned, long-term strategic vision for growing shareholder value and, on behalf of our shareholders, we thank him for his service.

Information for Shareholders

MEG Energy Corp. shares are traded on the Toronto Stock Exchange under the symbol "MEG".

Transfer Agent

Olympia Trust Company
Toll Free: 800-727-4493
cssinquiries@olympiatrust.com
www.olympiatrust.com

Auditor

PricewaterhouseCoopers LLP

Independent Reserve Evaluator

GLJ Petroleum Consultants

Annual General Meeting

May 2, 2013
Bow Glacier Room, Centennial Place
Third Floor West, 250 – 5 Street SW
Calgary, Alberta

Head Office

8th Floor, 520 – 3 Avenue SW
Calgary, Alberta, Canada
T2P 0R3
T403-770-0446
info@megenergy.com

Analyst and Investor Inquiries

Helen Kelly
Director, Investor Relations
403-767-6206
invest@megenergy.com

Further Information

MEG's financial reports, annual regulatory filings and news releases are available at **www.sedar.com** and on our website at **www.megenergy.com** investors. You can sign up to receive news releases and notifications of filings by visiting our website and clicking on the **Email Sign-Up** button at the top of the page.

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