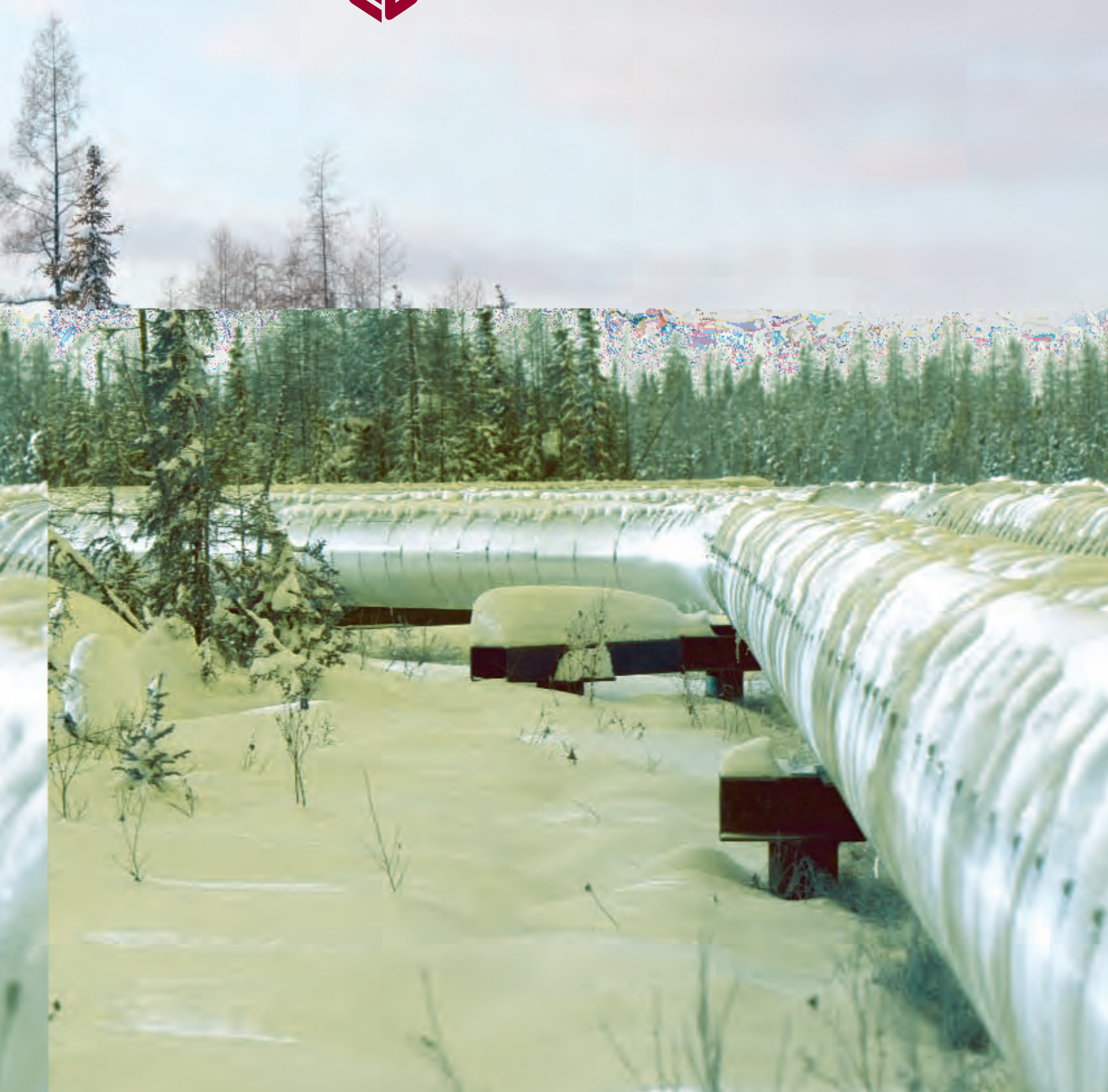




MEG ENERGY







MEG ENERGY CORP.

ANNUAL REPORT 2010

MEG ON THE MOVE
04

OPERATIONAL AND FINANCIAL OVERVIEW
05

HIGHLIGHTS OF 2010
07

OBJECTIVES FOR 2011
07

MESSAGE TO SHAREHOLDERS
09

MEG PROJECTS
11

RESERVES AND RESOURCES SUMMARY
14

MD&A
15

FINANCIAL STATEMENTS
42

CORPORATE INFORMATION
66

MEG AGM MAY 5, 2011 3-5 PM

BOW GLACIER ROOM (3RD FLOOR) CENTENNIAL PLACE, WEST TOWER • 250 5TH STREET SW CALGARY, AB T2P 0R3



MEG ON THE MOVE...

- MEG Energy Corp. (MEG) was incorporated in 1999 and is focused on sustainable *in situ* oil sands development and production in the southern Athabasca oil sands region of Alberta, Canada.
- MEG has amassed a concentrated land position comprising over 850 sections of oil sands leases. As of December 31, 2010, GLJ Petroleum Consultants Ltd. estimated that the oil sands leases it had evaluated contained 1.9 billion barrels of proved plus probable reserves and 3.7 billion barrels of contingent resources (best estimate).
- MEG is actively developing two commercial projects, at Christina Lake and at Surmont. Production at the Christina Lake Project is currently exceeding the design capacity of 25,000 barrels per day. Once all phases are complete, these two projects are anticipated to have the capacity to produce over 300,000 barrels of bitumen per day.
- MEG is developing its projects using an extraction method known as steam assisted gravity drainage, or SAGD.
- SAGD technology minimizes the surface footprint required to recover bitumen so that MEG's facilities only occupy 10-15% of the land surface of a producing lease.
- MEG utilizes clean, efficient cogeneration technologies that create steam and electricity from one fuel source, resulting in a more efficient use of natural gas.
- The steam-to-oil ratios (SORs) at MEG's facilities are among the lowest in industry, which results in lower emissions, lower operating costs and reduced capital intensity on a per barrel basis.



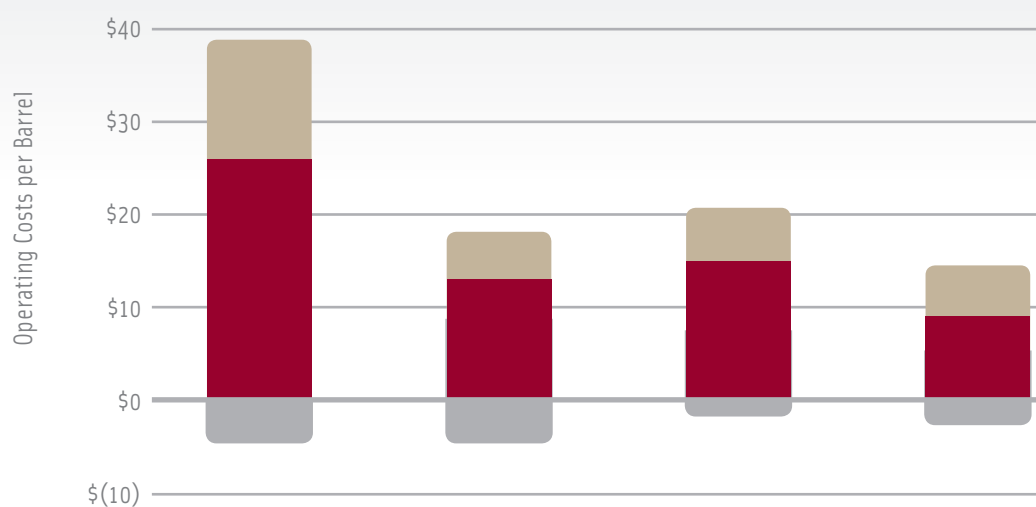
OPERATIONAL AND FINANCIAL OVERVIEW

OPERATIONAL AND FINANCIAL HIGHLIGHTS

(\$000 except per share amounts and as noted)	2010				
	Q1	Q2	Q3	Q4	Total
Bitumen production (bbls/d)	13,398	24,412	19,339	27,744	21,257
Total revenue, net of royalties	126,354	210,534	154,994	246,337	738,219
Operating earnings (loss) (1)	(16,797)	7,769	2,689	19,456	13,117
Operating earnings (loss) per share, diluted (1)	(0.09)	0.05	0.01	0.10	0.07
Net income (loss)	(485)	(31,658)	25,742	46,498	40,097
Net income (loss) per share, diluted	0.00	(0.19)	0.14	0.24	0.22
Cash flow from operations (1)	1,893	51,404	34,430	74,119	161,846
Cash flow from operations per share, diluted (1)	0.02	0.29	0.19	0.38	0.88
Long-term debt	1,006,902	1,050,120	1,017,176	979,998	979,998
Capital investment	91,809	158,378	97,005	147,438	494,630

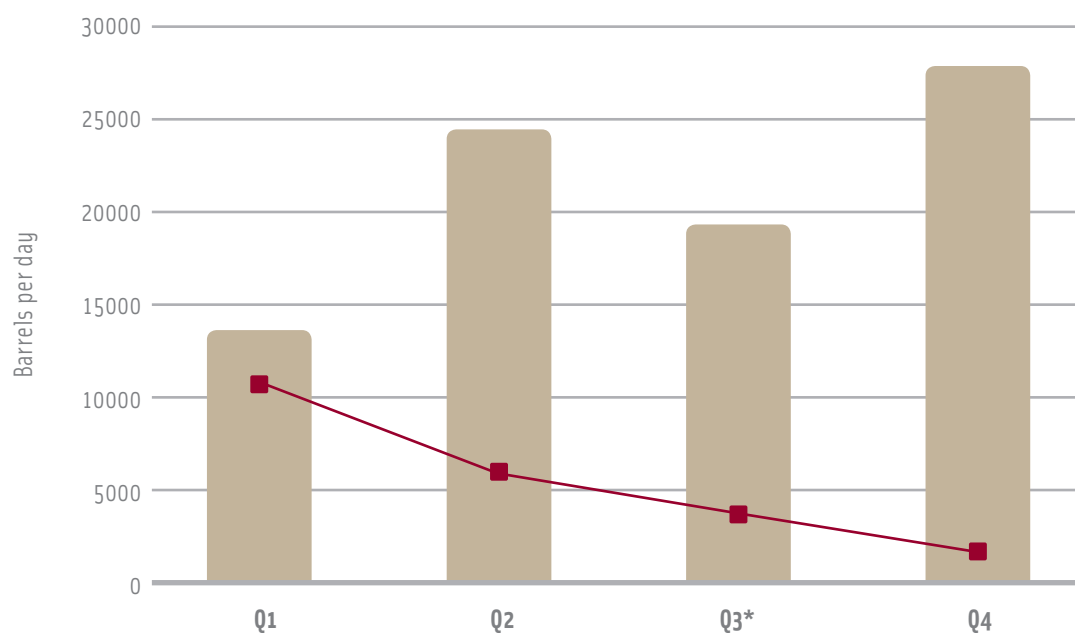
(1) Operating earnings, cash flow from operations and the related per share amounts do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. The Corporation uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the Corporation's ability to internally fund future growth expenditures. These "Non-GAAP Measurements" are reconciled to net income (loss) in accordance with Canadian GAAP under the heading "Non-GAAP Measurements" in the Management Discussion and Analysis.

TOTAL OPERATING COSTS



	Q1	Q2	Q3	Q4
Energy costs	\$ 12.55	\$ 5.95	\$ 5.29	\$ 4.87
Power sales	\$ (5.22)	\$ (5.24)	\$ (2.15)	\$ (2.88)
Net energy costs	\$ 7.33	\$ 0.71	\$ 3.14	\$ 1.99
Non energy costs	\$ 26.46	\$ 12.85	\$ 15.32	\$ 9.35
Net operating costs	\$ 33.79	\$ 13.56	\$ 18.46	\$ 11.34

PRODUCTION AND STEAM OIL RATIO



Production (bbls/d)	13,398	24,412	19,339	27,744
SOR	3.1	2.5	2.4	2.3

* Scheduled plant turnaround

HIGHLIGHTS OF 2010

- Exceeded nameplate capacity for bitumen production at Phase 2 of the Christina Lake Project
- Achieved an average steam-to-oil ratio (SOR) of 2.5
- 85 MW cogeneration facility reached design power and steam generation capacity
- Successful execution of plant turnaround in September followed by quick ramp-up of production
- Excellent safety record with a Recordable Incident Frequency of zero for MEG employees
- Achieved amongst the best GHG emissions performance records in the *in situ* industry, approximately 33% lower than industry average¹, on an intensity basis (tonnes CO₂eq/bbl)
- Increased 2P reserves by 13% from 2009

OBJECTIVES FOR 2011

- Average 25,000 – 27,000 bbls/d of bitumen production
- Maximize productivity and reliability of existing assets
- Continue with Phase 2B development, targeting over 90% completion of engineering and the delivery of all key long-lead equipment by the end of the year
- Obtain ERCB approval for Phase 3 expansion at the Christina Lake Project, subject to completion of regulatory process
- Further delineate leases in the Growth Properties

1. Based on 2009 CAPP data.





MESSAGE TO SHAREHOLDERS

OUR STORY

Over the past 11 years, MEG Energy has quietly become one of the industry's premier thermal oil sands developers. The company began during the economic downturn of 1999 which saw volatile commodity prices, an oversupply of crude and as a result, a conservative approach to development. It was at this time that MEG started acquiring leases in Alberta's strongest *in situ* oil sands resource base – the southern Athabasca region.

Today MEG has secured over 850 square miles of oil sands leases and has identified two major development projects. The first in Christina Lake, a multi-phased SAGD installation which saw production of over 27,500 barrels per day at year-end and the second, 32 square miles of oil sands leases located in the Surmont area. After spending 10 years positioning our company and clearly defining our resource base, MEG launched its initial public offering last summer. The market responded strongly and as a result, our IPO was heralded the most successful Canadian IPO of 2010 by the Canadian Dealmakers. I am pleased to report that the success of our IPO has extended to our shareholders, who have seen MEG's share price rise by more than 30% from August to year-end.

The IPO has paved the way for further success long into the future. We continue to remain focused on four fundamental areas that have guided the success of our company to-date: our reserves and resources, our plan, our operations and our people.

OUR RESOURCE BASE

MEG has successfully established itself as a dominant player in the development of the southern Athabasca oil sands area. Currently the company has a total of 1.9 billion barrels of proved plus probable reserves and 3.7 billion barrels of contingent resources (best estimate) within Christina Lake, Surmont and various growth properties in the region as evaluated by GLJ Petroleum Consultants Ltd.

Over the past few years, the Christina Lake Project has seen significant development. Phases 1 and 2 began production in 2008 and 2009 respectively with a combined plant capacity of 25,000 barrels of bitumen per day. We are proud to report that this capacity was achieved within 10 months, a record-setting pace for the industry. Construction is underway for Phase 2B and when completed, is expected to add an additional 35,000 barrels per day in design capacity. The final phase for Christina Lake, Phase 3, is a multi-phased development in the regulatory approval stage. Phase 3 is expected to add an additional design capacity of 150,000 barrels of bitumen per day, ultimately taking the Christina Lake Project's total design capacity to over 200,000 barrels per day.

In addition to Christina Lake, MEG plans to develop oil sands leases in the Surmont area, located approximately 50 kilometers north of Christina Lake. We believe that the resources at Surmont can support a staged development with the potential of reaching 100,000 barrels per day. Pending regulatory approval, this project could begin steaming as early as 2018. MEG also holds over 750 square miles of oil sands leases in various growth properties in the region. These leases are in the resource definition stage and could provide significant additional development opportunities.

Securing quality resources is one of the cornerstones of MEG's strategic plan. The leases MEG has acquired have laid the foundation for sustained growth for years to come.

OUR PLAN

With a strong asset base in place, MEG is focused on implementing a calculated and responsible plan featuring staged development and a commitment to delivering maximum value to our shareholders. Developing our resource base at a prudent pace ensures a strong balance sheet and healthy cash flows. Staged development provides us with flexibility to adjust project schedules in response to market conditions. It also allows us to apply valuable knowledge gained from earlier SAGD projects to improve subsequent

developments. With Phases 1 and 2 performing above expectations and ahead of schedule and the necessary funding in place for our next phase (Phase 2B), MEG is in a great position to continue to execute its growth strategy. The second essential component of the plan is to capture value chain opportunities that will enhance the value of every barrel of bitumen produced. By working on the value chain, net backs are improved, which strengthens MEG's cash flow and positions the company well for further developments.

OUR OPERATIONS

MEG has demonstrated an unparalleled commitment to operational excellence. Over the past year we were able to enjoy a number of operational successes that stand as a testament to the dedication and hard work of our team. From our industry leading ramp-up, to sustaining our production rates in excess of design capacity, to maintaining low steam-to-oil ratios and achieving lower year-over-year operating costs, MEG has made substantial gains towards operational excellence. It was an honour and a testament to the experience of our team when MEG was recognized as the 2010 Oil Sands Producer of the Year by Oilsands Review magazine. Going forward, MEG will continue to focus on minimizing costs and increasing plant efficiencies, in order to get greater value for its shareholders.

We are also proud of our environmental performance. We have an opportunity to be a supplier of the world's energy needs. It is our responsibility to do so in a way that minimizes the environmental impact associated with energy development. I am pleased to report that MEG was among the *in situ* industry leaders in CO₂ emissions performance in 2010, with a greenhouse gas intensity approximately 33% lower than the most recent CAPP industry average. Through our use of cogeneration technology, we are continuing to help green Alberta's electrical grid. MEG's contribution of green electricity helped offset over 238,000 tonnes of GHG production from other sources, the equivalent of removing over 45,000 cars off the road in 2010.

OUR PEOPLE

Our success has been a team effort on every level. At MEG we have worked hard to create an environment that attracts and retains the industry's brightest minds. Our employees are talented, committed and proud to be a part of our team. By maintaining a strong culture, valuing individual contribution and focusing on teamwork, MEG has created an environment where ideas can be shared resulting in increased productivity and innovative approaches to our business.

OUR FUTURE – MEG IS ON THE MOVE

As I reflect on our 2010 achievements, I'm proud of the significant progress we've made. This has been a profound and exciting year for our organization. The next chapter will see continued growth and development of our resource base with a concentrated effort on reducing costs and enhancing the value of every barrel produced. We will remain focused on finding new ways to enhance efficiencies and further grow our production capabilities. We will do so by continuing to focus on the four building blocks to our success – a great resource base, a strong development plan, a keen operational focus and a talented team. On behalf of our employees, management and Board of Directors, I thank you for your continued support.



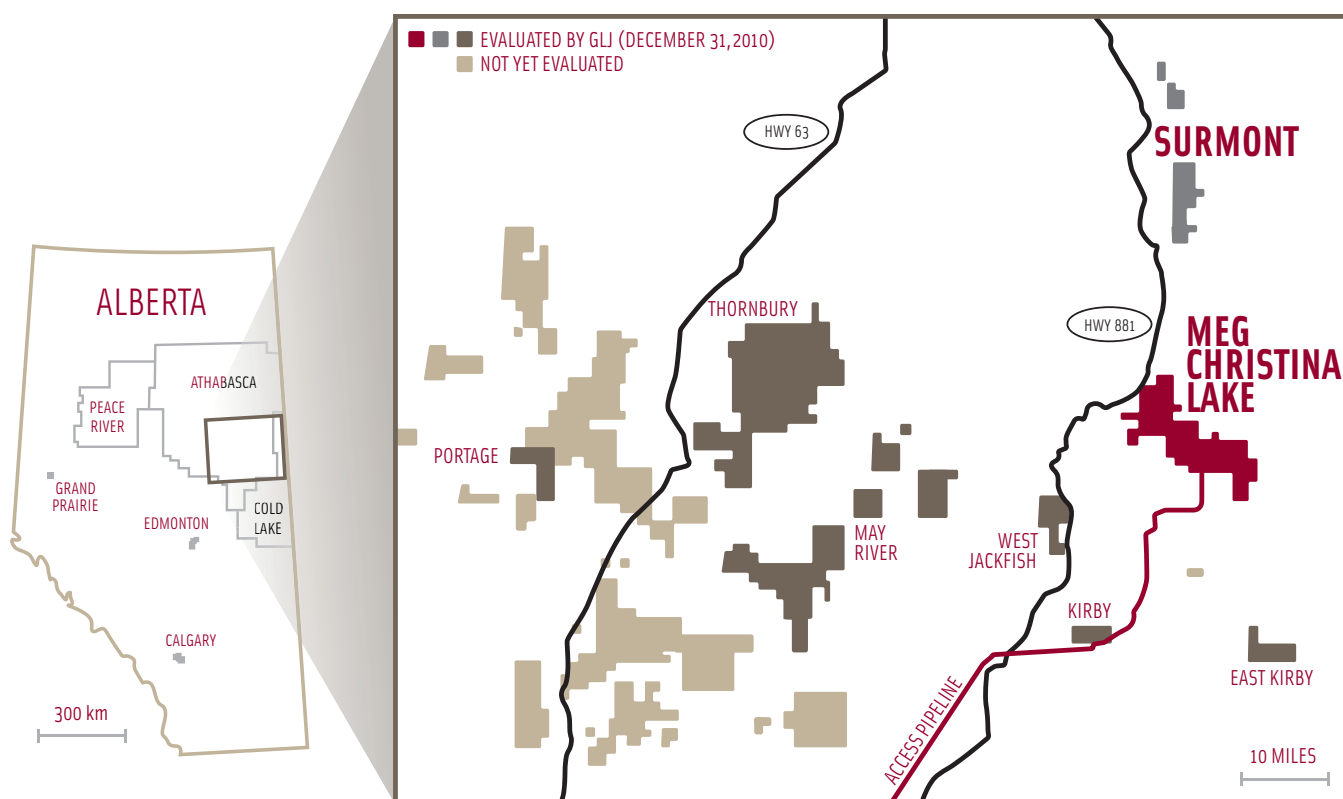
Bill McCaffrey

President & CEO

February 24, 2011



MEG OIL SANDS LEASES (AS OF DECEMBER 31, 2010)



CHRISTINA LAKE

MEG owns a 100% working interest in the oil sands leases of the Christina Lake Project, a SAGD facility situated in Alberta's southern Athabasca region. The company is developing its Christina Lake Project in multiple phases. Phases 1 and 2 were completed in 2007 and 2009 respectively, with combined designed bitumen production capacity of 25,000 bbls/d. Production from the two integrated phases averaged 21,257 bbls/d in 2010, at an average SOR of 2.5. Production during the fourth quarter of 2010 averaged 27,744 bbls/d, approximately 10% above the nominal design capacity.

Phase 2 is equipped with a cogeneration facility capable of generating 85 MW of electricity. Phases 1 and 2 combined currently utilize 10 – 12 MW of power, with surplus electricity being sold into the Alberta Power Pool. This strategy helps significantly reduce MEG's net energy costs.

Regulatory approval was granted for the development of Phase 2B of the Christina Lake Project in 2009. Detailed engineering and procurement are currently underway for the expansion and site construction has commenced. When completed, Phase 2B will add an additional 35,000 bbls/d of bitumen processing capacity. In 2011, the company anticipates receiving regulatory approval for Phase 3, a multi-phased expansion that will support an additional 150,000 bbls/d of bitumen production. MEG anticipates the design capacity of the Christina Lake Project will increase to approximately 210,000 bbls/d of bitumen once fully developed.

SURMONT

MEG owns a 100% working interest in the Surmont Project, which is comprised of 32 square miles of lands in the southern Athabasca region, approximately 50 kilometers north of the Christina Lake Project. The company plans to file a regulatory application in 2011 for the development of up to a 100,000 bbls/d project, to be constructed in multiple stages.

GROWTH PROPERTIES

In addition, MEG has a 100% interest in over 700 square miles of lands west of the company's existing Christina Lake Project. Over the last four years, the company has acquired seismic data and drilled test wells to further define its resources in the Growth Properties. The company is conducting an ongoing core hole program to identify opportunities for future development.

ACCESS PIPELINE

MEG owns a 50% interest in the Access Pipeline, a strategic 215-mile dual pipeline system with current capacity of 70,000 bbls/d of condensate and 156,000 bbls/d of blended bitumen. The pipeline system consists of a 16-inch diluent line from the Edmonton area to the Christina Lake Project, a 24-inch blend line to transport diluted bitumen (dilbit) from Christina Lake to the Sturgeon Terminal and a 30-inch extension from the terminal to Edmonton. The Sturgeon Terminal is a blending and storage facility northeast of Edmonton that is also an important component of the Access Pipeline.

The Access Pipeline offers a number of strategic advantages. The area in which the Sturgeon Terminal is located is a regional refining and transportation hub and a significant source of diluent in the region. By securing a proprietary means of transporting diluents to Christina Lake and dilbit to Edmonton, MEG has reduced its dependence on third parties, lowered its overall diluent and transportation costs and enhanced its ability to realize superior pricing for its bitumen blend by accessing multiple end-markets.

Further, the company plans to extend the Access Pipeline to provide its economic benefits to the Surmont Project and the Growth Properties. The Access Pipeline's current capacity can be increased by adding pumping stations to the system in order to accommodate the Phase 2B expansion at Christina Lake. In addition, segments of the blend line can be looped to further increase capacity to accommodate additional volume produced from future projects.





RESERVES AND RESOURCES SUMMARY

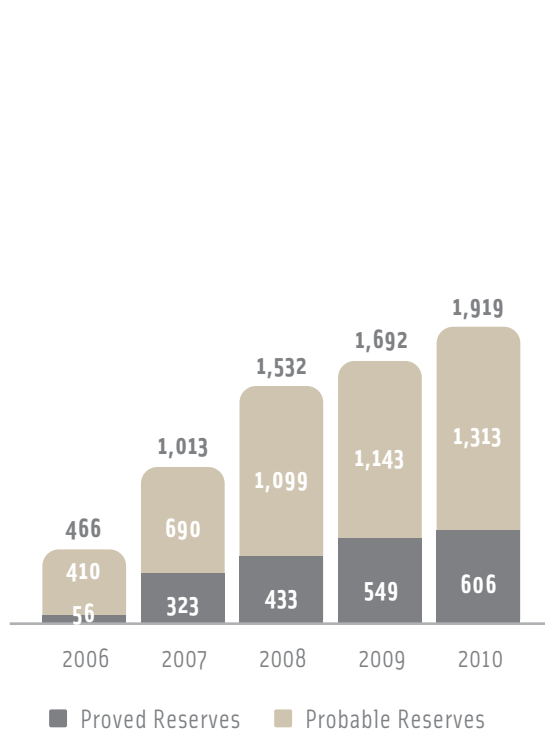
Summary of Bitumen Reserves and Contingent Resources (Best Estimate) as of December 31, 2010 (1)

(MMBBLs)	PROVED RESERVES	PROBABLE RESERVES	CONTINGENT RESOURCES
Christina Lake	606	1,313	1,061
Surmont	-	-	837
Growth Properties	-	-	1,818
Total	606	1,313	3,716

(1) The estimates of reserves and contingent resources (best estimate) contained within this table and elsewhere within this annual report are drawn from the Reserves and Resources Report prepared by GLJ Petroleum Consultants Ltd. effective as of December 31, 2010. Please see the "Notice Regarding Reserves and Resources Estimates and Forward-Looking Information" for important information regarding the estimates and classification of MEG's reserves and contingent resources.

2P RESERVES

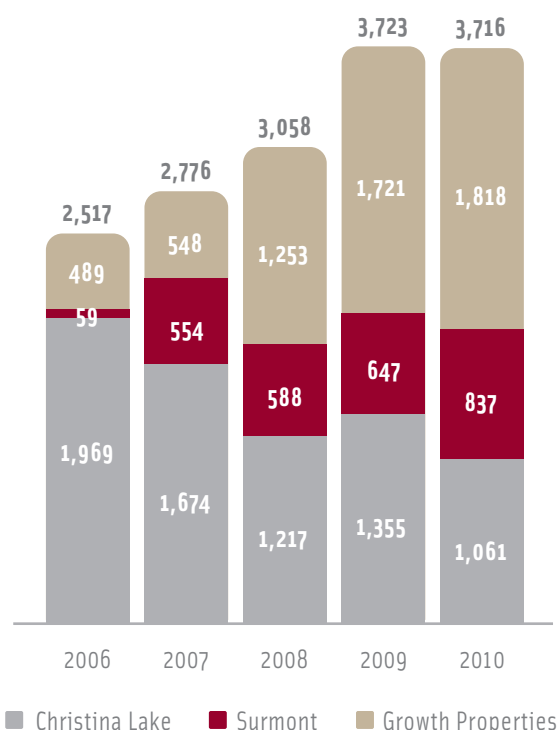
(mmbbls)



CHRISTINA LAKE ONLY

BEST ESTIMATE CONTINGENT RESOURCES

(mmbbls)



NOTICE REGARDING RESERVES AND RESOURCES ESTIMATES AND FORWARD-LOOKING INFORMATION

This annual report contains estimates of MEG's contingent resources. There is no certainty that it will be commercially viable to produce any portion of the volumes that have been classified as contingent resources. Further information regarding the definition of contingent resources and the classification and estimates of reserves and contingent resources are contained in MEG's annual information form dated February 24, 2011 which is available at www.sedar.com. The statements relating to estimates of reserves and contingent resources along with certain other statements within this annual report constitute forward-looking information. All such statements are subject to the "Management's Discussion and Analysis – Forward Looking Information" section of this annual report.

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") is dated February 23, 2011 and should be read in conjunction with the Corporation's audited financial statements and notes thereto for the year ended December 31, 2010. All tabular amounts are stated in thousands of Canadian dollars unless indicated otherwise.

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, steam-oil-ratios, 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, production capacities and performance of the Access Pipeline, the Stonefell Terminal, the future phases and expansions of the Christina Lake Project, the Surmont Project and MEG's other properties and facilities; 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 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 "Risk Factors" and "Regulatory Matters" within MEG's annual information form dated February 24, 2011 (the "AIF") along with MEG's other public disclosure documents.

Statements in this MD&A relating to reserves and resources are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the described reserves and resources, as the case may be, exist in the quantities predicted or estimated, and can be profitably produced in the future. This MD&A contains estimates of the Corporation's contingent resources. There is no certainty that it will be commercially viable to produce any portion of the Corporation's contingent resources. For further information regarding the classification and uncertainties related to MEG's

estimated reserves and resources please see "Independent Reserve and Resource Evaluation" in the AIF. Copies of the AIF and of MEG's other public disclosure documents are available through the SEDAR website (www.sedar.com) or by contacting MEG's investor relations department.

NON-GAAP 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 Canadian generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Corporation may not be comparable to similar measures presented by other companies. The Corporation uses these non-GAAP 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-GAAP measures should not be considered as an alternative to or more meaningful than net income (loss), as determined in accordance with Canadian GAAP, as an indication of the Corporation's performance. The non-GAAP operating earnings, cash flow from operations and cash operating netback measures are reconciled to net income (loss), as determined in accordance with Canadian GAAP, under the heading "Non-GAAP Measurements" below.

OVERVIEW

The Corporation is focused on sustainable *in situ* oil sands development and production in the southern Athabasca region of Alberta, Canada. The Corporation is actively developing enhanced oil recovery projects that utilize steam assisted gravity drainage ("SAGD") extraction methods.

The Corporation owns a 100% working interest in over 850 sections of oil sands leases. In a report effective December 31, 2010 (the "GLJ Report"), GLJ Petroleum Consultants Ltd. ("GLJ"), an independent reservoir engineering firm, estimated that the Corporation's oil sands leases it had evaluated contained 1.9 billion barrels of proved plus probable bitumen reserves and 3.7 billion barrels of contingent resources (best estimate). The Corporation has identified two commercial SAGD projects; the Christina Lake Project and the Surmont Project. Based on the GLJ Report, it is estimated that the Christina Lake Project can support over 200,000 barrels per day of sustained production for 30 years and that the Surmont Project can support 100,000 barrels per day of sustained production for over 20 years. In addition, the Corporation holds other leases known as the Growth Properties that are in the resource definition stage and that provide significant additional development opportunities.

On November 30, 2010, the Corporation's board of directors approved the 35,000 bbls/d facility expansion of Phase 2, called Phase 2B. The current cost estimate for the Phase 2B expansion is \$1.4 billion. The Corporation has commenced detailed facilities engineering and equipment procurement, and plans to commence site construction in 2011 with first production scheduled for 2013. Phase 2B is designed to increase production capacity of the Christina Lake project to 60,000 bbls/d. Development of the future phases of Christina Lake and other projects is discretionary, and there can be no assurance that development will be completed as currently planned.

The Corporation also holds a 50% interest in a dual pipeline system, which connects the Christina Lake project to a large regional upgrading, refining and transportation hub in the Edmonton area (the "Access Pipeline"). The Access Pipeline and its associated blending facilities are in operation and provide the Corporation with the ability to transport diluents to Christina Lake and a blend of bitumen and condensate (called dilbit) from Christina Lake to Edmonton to supply a range of North American and global refining markets.

SUMMARY ANNUAL INFORMATION

(\$ 000, except per share amounts)	2010	2009	2008
Total revenue, net of royalties	738,219	25,994	13,716
Net income (loss)	40,097	51,176	(179,977)
Per share – basic	0.23	0.37	(1.44)
Per share – diluted	0.22	0.36	(1.44)
Total assets	5,017,631	4,269,493	3,122,740
Total long-term financial liabilities	1,012,149	1,058,274	890,095

Net operating costs from oil sands operations in 2008 through to November 30, 2009 were capitalized. Total revenue prior to December 1, 2009 consisted primarily of interest earned on the cash balances. Effective December 1, 2009, bitumen blend and power sales were included in total revenue which increased revenue from prior years.

Net income (loss) was primarily influenced by foreign exchange gains and losses (2010 – \$49.1 million gain, 2009 – \$120.1 million gain, 2008 – \$144.3 million loss) 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, risk management activities not accounted for as hedges (2010 – \$21.8 million loss; 2009 – \$10.1 million loss; 2008 – \$29.3 million loss) and modification of long-term debt (2010 – nil; 2009 – \$21.3 million loss; 2008 – nil). Total assets increased each year from 2008 through 2010 due to capital investment in the Christina Lake Project and the Access Pipeline, as well as resource definition and oil sands lease acquisitions at the Surmont Project and the Growth Properties.

The investment activity was funded by private placement share issues raising \$545.4 million and \$890.0 million net of issue costs in 2008 and 2009, respectively, and the Corporation's \$663.5 million, net of issue costs, initial public offering in 2010. In addition, the Corporation amended, extended and increased its term loan by US\$300 million in 2009. For a detailed discussion of the debt amendment, see "LIQUIDITY AND CAPITAL RESOURCES – Financing Activities".



OPERATIONAL AND FINANCIAL HIGHLIGHTS

The following table summarizes selected financial and operational information of the Corporation for the periods ended:

	Year ended December 31	
(\$000 except per share amounts and as noted)	2010	2009
Bitumen production – bbls/d	21,257	3,467
Bitumen realization – \$/bbl	51.76	45.01
Operating costs – \$/bbl:		
Energy	6.47	12.18
Non-energy	14.39	43.62
Total operating costs – \$/bbl	20.86	55.80
Steam-to-oil ratio	2.5	3.9
Operating earnings (loss)(1)	13,117	(39,944)
Per share, diluted(1)	0.07	(0.28)
Net income (loss)	40,097	51,176
Per share, basic	0.23	0.37
Per share, diluted	0.22	0.36
Cash flow from operations(1)	161,846	(32,461)
Per share, diluted(1)	0.88	(0.23)
Capital investment	494,630	351,342

(1) Operating earnings, cash flow from operations and the related per share amounts do not have standardized meanings prescribed by Canadian GAAP and therefore may not be comparable to similar measures used by other companies. The Corporation uses these non-GAAP 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 growth expenditures. These "Non-GAAP Measurements" are reconciled to net income (loss) in accordance with Canadian GAAP under the heading "Non-GAAP Measurements".

For the year ended December 31, 2010 bitumen production averaged 21,257 barrels per day compared to 3,467 barrels per day in 2009. The increase in production is due to the increased volumes from the ramp-up of Phase 2 of the Christina Lake Project.

For the year ended December 31, 2010 operating costs were \$20.86 per barrel compared to \$55.80 per barrel in 2009. Operating costs per barrel decreased primarily as a result of the increase in production as a result of the ramp-up of the Christina Lake Phase 2 facility.

The average steam-to-oil ratio ("SOR") for the year ended December 31, 2010 was 2.5 compared to an average SOR of 3.9 in 2009. The SOR has decreased throughout 2010 as the Phase 2 well pairs have quickly progressed through the circulation phase and entered into normal operations. The early success of the production ramp-up, and improved SOR, has enabled the Corporation to performance test the integrated Phase 1 and 2 facilities and exceed the plant design production capacity.

Operating earnings of \$13.1 million for the year ended December 31, 2010 represent an increase of \$53.0 million from a \$39.9 million loss for the same period in 2009. The increase in operating earnings primarily resulted from higher production volumes related to the ramp-up of the Christina Lake Phase 2 operations.

Net income for the year ended December 31, 2010 was \$40.1 million compared to \$51.2 million in 2009. This change was primarily 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. For the year ended December 31, 2010 there was an unrealized foreign exchange gain of \$52.2 million for the translation of the debt compared to a \$127.3 million unrealized gain in 2009. The reduction in the foreign exchange gains compared to 2009 is offset by the fact that net income during the year ended December 31, 2009 only included one month of income from operations. Effective December 1, 2009, the Corporation commenced planned principal operations and ceased capitalizing blend revenue, operating costs and interest costs for Phases 1 and 2 of the Christina Lake Project.

Cash flow from operations for the year ended December 31, 2010 totalled \$161.8 million, an increase of \$194.3 million from 2009. The increase was the result of cash flows generated from Phase 2 bitumen production.

Capital investment for the year ended December 31, 2010 increased from \$351.3 million in 2009 to \$494.6 million. The increase is due to increased investment in Christina Lake Phase 2B as well as the \$42.5 million purchase of lands and assets associated with the Stonefell Terminal tank farm construction project and the \$54.9 million purchase of undeveloped lands in the Surmont area.

NON-GAAP MEASUREMENTS

The following table reconciles the non-GAAP measurements "Operating earnings (loss)" and "Cash flow from operations" and "Cash operating netbacks" to "Net income (loss)", the nearest Canadian GAAP measure. Operating earnings (loss) is defined as net income (loss) as reported excluding the after-tax gains and losses on foreign exchange, risk management, loss on modification of long-term debt, and change in fair value of other assets. Cash flow from operations excludes realized risk management, foreign exchange losses, and loss on modification of long-term debt and the net change in non-cash operating working capital while the Canadian GAAP measurement "Cash from operating activities" includes these items. Cash operating netback is comprised of petroleum and power sales less royalties, operating costs, cost of diluents and transportation and selling costs. Prior to December 1, 2009 these items were capitalized as the Corporation had not commenced planned principal operations.



	Year ended December 31	
Non-GAAP Measurements (\$000)	2010	2009
Net income (loss)	40,097	51,176
Add (deduct):		
Foreign exchange gains, net of tax(1)	(43,316)	(116,817)
Risk management losses, net of tax(2)	16,336	7,577
Change in fair value of other assets, net of tax(3)	-	2,156
Loss on modification of long-term debt, net of tax(4)	-	15,964
Operating earnings (loss)	13,117	(39,944)
Add (deduct) non-cash items:		
Stock-based compensation	14,439	12,912
Depletion, depreciation and accretion	124,801	3,103
Interest expense	170	336
Future income taxes, operating	9,319	(8,868)
Cash flow from operations	161,846	(32,461)
Add (deduct):		
Net operating loss capitalized	-	(21,010)
Interest income	(7,933)	(2,572)
General and administrative	36,427	24,295
Research and development	5,384	4,690
Interest expense	44,591	4,183
Cash operating netback	240,315	(22,875)

(1) Foreign exchange gains result primarily from the translation of US dollar denominated long-term debt and debt service reserve to period-end exchange rates.

(2) Risk management losses result from the Corporation's interest rate swaps entered into to fix a portion of its variable rate long-term debt.

(3) Change in fair value of other assets results from fair value changes in certain long-term investments.

(4) Loss on modification of long-term debt results from modifications to the Corporation's senior secured credit facility on December 23, 2009.

SUMMARY OF QUARTERLY RESULTS

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

	2010				2009			
(\$ millions, except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue, net of royalties	246.3	155.0	210.5	126.4	23.8	0.4	0.5	1.3
Net income (loss)	46.5	25.7	(31.7)	(0.4)	(16.0)	44.1	56.7	(33.6)
Per share – basic	0.25	0.14	(0.19)	0.00	(0.11)	0.31	0.41	(0.26)
Per share – diluted	0.24	0.14	(0.19)	0.00	(0.11)	0.30	0.40	(0.26)

Revenue for the first 11 months in 2009 was primarily from interest earned on the investment of surplus cash. Commencing December 2009, revenues also include the revenue from the sale of bitumen blend and power. Effective December 1, 2009, the Corporation commenced planned principal operations and ceased capitalizing blend revenue, operating costs and interest costs for Phases 1 and 2 of the Christina Lake Project.

Net income (loss) during the periods noted were 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, risk management activities for interest rate swaps, and costs for modification of long-term debt. The net income (loss) was also positively impacted by the inclusion of blend revenue, operating costs and interest costs for Phases 1 and 2 of the Christina Lake Project as planned principal operations commenced December 1, 2009 and the Corporation ceased capitalizing these items.

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

	Year ended December 31		2010				2009			
	2010	2009	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Commodity prices (average prices)										
Crude oil prices										
West Texas Intermediate (WTI) (US\$/bbl)	79.52	61.80	85.13	76.20	78.03	78.71	76.19	68.30	59.62	43.08
Western Canadian Select (WCS) (CDN\$/bbl)	67.23	58.66	67.87	62.94	65.60	72.51	67.66	63.74	60.64	42.60
Differential – WTI/WCS (CDN\$/bbl)	14.69	11.89	18.35	16.24	14.59	9.42	12.82	11.21	8.95	11.05
Differential – WTI/WCS (%)	18.0%	17.0%	21.0%	20.5%	18.2%	11.5%	15.9%	15.0%	12.9%	20.6%
Natural gas prices										
AECO (CDN\$/mcf)	4.11	4.12	3.56	3.70	3.84	5.33	4.21	3.01	3.64	5.61
Electric power prices										
Alberta Power Pool average price (CDN\$/MWh)	50.91	47.80	45.95	35.77	81.15	40.78	46.06	49.49	32.30	63.35
Foreign exchange rates										
Average Canadian / U.S. dollar exchange rate	1.0301	1.1415	1.0128	1.0391	1.0276	1.0409	1.0563	1.0974	1.1672	1.2453
Corporation results										
Blend Sales (CDN\$/bbl)	63.03	53.40	63.95	60.84	60.94	68.06	61.11	58.36	55.37	33.22
Differential – WTI/Blend (CDN\$/bbl)	18.88	17.14	22.27	18.33	19.25	13.88	19.37	16.59	14.21	20.43
Differential – WTI/Blend (%)	23.0%	24.3%	25.8%	23.2%	24.0%	16.9%	24.1%	22.1%	20.4%	38.1%
Diluent cost (CDN\$/bbl)	87.27	73.56	89.95	83.46	86.20	88.56	83.79	74.52	65.78	59.10
Bitumen sales (CDN\$/bbl)	51.76	45.01	51.43	51.73	48.73	58.10	51.70	52.08	50.95	21.94
Bitumen sales (bbls/d)(1)	21,292	3,416	27,648	19,376	24,562	13,447	5,920	2,493	2,136	3,093

(1) The Corporation completed a planned plant turnaround in the third quarter of 2010.

RESULTS OF OPERATIONS

Since the commencement of Phase 2 steaming operations in August 2009 production at the integrated Phase 1 and Phase 2 facilities has increased to average 27,744 barrels per day during the fourth quarter of 2010, exceeding the design capacity of 25,000 barrels per day. For the year ended December 31, 2010 the average SOR was 2.5 compared to an average SOR of 3.9 in 2009. The average SOR for the fourth quarter of 2010 was 2.3. SOR is an important efficiency indicator which measures the amount of steam that is injected into the reservoir in relation to bitumen produced. A lower SOR indicates a more efficient steam assisted gravity drainage ("SAGD") process. SORs are higher in the start-up period than in steady state operations due to the initial steam circulation period and lower initial production rates during ramp-up.

The Corporation's 85 MW cogeneration facility produces approximately 70% of the steam for Phase 1 and 2 SAGD operations and is operating near capacity. MEG's processing facility is utilizing the heat produced by the cogeneration facility and approximately 10 – 12 MW of the power generated. Beginning in October 2009, surplus power has been sold into the Alberta Power Pool electricity grid.

The following table summarizes the Corporation's results of operations for the periods indicated:

OPERATING SUMMARY

	Year ended December 31	
	2010	2009
Cash operating netback (\$000)		
Blend sales(1)	717,610	94,295
Cost of diluent(2)	(315,350)	(38,180)
Bitumen sales	402,260	56,115
Transportation and other selling costs	(12,480)	(12,767)
Royalties	(16,521)	(1,705)
Net bitumen revenue	373,259	41,643
Operating costs - energy	(50,288)	(15,183)
Operating costs - non-energy	(111,853)	(54,383)
Power sales	29,197	5,048
Cash operating netback(3)	240,315	(22,875)
Less capitalized(4)	-	(21,010)
Cash operating netback in statement of operations(4)	240,315	(1,865)

	Year ended December 31	
	2010	2009
Production and Sales Volume Summary (bbls/d)		
Blend sales(1)	31,192	4,838
Diluents(2)	(9,900)	(1,422)
Bitumen sales	21,292	3,416
(Increase) decrease in inventory	(35)	51
Total bitumen production	21,257	3,467
Power sales (MWh)	585,476	98,914
Power realization (CDN\$/MWh)	49.87	51.97

	Year ended December 31	
Cash operating netback (\$ per barrel)	2010	2009
Bitumen sales	51.76	45.01
Transportation and other selling costs	(1.61)	(10.24)
Royalties	(2.13)	(1.37)
Net bitumen revenue	48.02	33.40
Operating costs – energy	(6.47)	(12.18)
Operating costs – non-energy	(14.39)	(43.62)
Power sales	3.76	4.05
Cash Operating Netback(3)	30.92	(18.35)

(1) Bitumen produced at the Christina Lake Project is mixed with purchased diluent and sold as bitumen blend. Diluent is a light hydrocarbon that improves the marketing and transportation quality of bitumen.

(2) Diluent volumes purchased and sold have been deducted in calculating bitumen production revenue and production volumes sold.

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

(4) Effective December 1, 2009, the Corporation commenced planned principal operations and ceased capitalizing net operating costs.

Bitumen sales in the year ended December 31, 2010 were \$402.3 million compared to \$56.1 million for the same period in 2009. The increase of \$346.2 million is due to higher production volumes from the start up of Christina Lake Phase 2 and higher selling prices. WTI averaged US\$79.52 per barrel (C\$81.91/bbl) in 2010 compared to US\$61.80 per barrel (C\$70.54/bbl) in 2009. Blend revenue averaged \$63.03 per barrel for the year ended December 31, 2010 compared to \$53.40 per barrel in 2009.

Energy operating costs represent the cost of gas purchased to operate the Corporation's once through steam generators and the cogeneration facility. Non-energy operating costs represent all other non-natural gas related operating expenses. Energy operating costs have decreased from \$12.18 per barrel for the year ended December 31, 2009 to \$6.47 per barrel for the year ended December 31, 2010. Non-energy operating costs were \$14.39 per barrel for the year ended December 31, 2010 compared to \$43.62 per barrel for the year ended December 31, 2009. Operating costs per barrel have decreased in 2010 primarily as a result of the increase in production from the ramp-up of Christina Lake Phase 2.

Power sales for the year ended December 31, 2010 were \$29.2 million compared to \$5.0 million in 2009. During the year ended December 31, 2010 the Corporation realized a price of \$49.87 per megawatt hour compared to the Alberta Pool average price of \$50.91 per megawatt hour. There will be variances to the Alberta Pool average price benchmark as it is based on the average daily price while power sales are priced on an hourly basis and can vary significantly each hour during the day.

During commissioning and start up it takes time for the reservoir to respond and for operations to work through the normal processing and treating issues associated with a new facility. Since Phase 1 was a pilot plant and Phase 2 was ramping-up production through 2009 and into 2010, current operating netback per barrel does not yet reflect the economies associated with a steady state facility operating at its design capacity. Operating cost per barrel has decreased in 2010 compared to 2009 as fixed costs are spread over the higher production volumes during this period. The Corporation anticipated volatility in operating results with the start up of Phase 2 but expects the volatility to become less pronounced as steady-state operations are achieved.

INTEREST INCOME

Interest income for the year ended December 31, 2010 increased to \$7.9 million from \$2.6 million for the year ended December 31, 2009. The increase was primarily due to an increase in average investment balances during 2010 compared to 2009.

GENERAL AND ADMINISTRATIVE COSTS

	Year ended December 31	
(\$000)	2010	2009
G&A Expense	36,403	24,295
Capitalized G&A	11,258	9,576
Total G&A Costs	47,661	33,871

General and administrative costs for the year ended December 31, 2010 totalled \$47.7 million, compared with \$33.9 million in 2009. The increase in costs primarily resulted from the planned growth in the Corporation's professional staff and costs to support the operations and development of its oil sands assets. The head office employee head count grew from 147 as of December 31, 2009 to 184 at December 31, 2010. For the year ended December 31, 2010 the Corporation capitalized salaries related to capital investment of \$11.3 million (2009 – \$9.6 million).

STOCK-BASED COMPENSATION

Stock-based compensation expense for the year ended December 31, 2010 was \$14.4 million compared to \$12.9 million in 2009. For the year ended December 31, 2010 the Corporation capitalized \$3.7 million (2009 – \$3.8 million) of stock-based compensation to property, plant and equipment.

RESEARCH AND DEVELOPMENT

Research and development expenditures relate to the Corporation's research of greenhouse gas management, bitumen quality improvement and related technologies and have been expensed. Research and development expenditures were \$5.4 million for the year ended December 31, 2010 compared to \$4.7 million in 2009.

FOREIGN EXCHANGE GAIN (LOSS)

	Year ended December 31		
(\$000)	2010	2009	
Long-term debt	52,186	127,258	
Debt service reserve	(2,195)	(3,832)	
US\$ denominated cash and cash equivalents	(1,445)	(4,843)	
Other	509	1,524	
Foreign exchange gain (loss)	49,055	120,107	
US\$ – Canadian \$ exchange rate			
As at December 31,	2010	2009	2008
C\$ equivalent of 1 US dollar	0.9946	1.0466	1.2246

The net foreign exchange gain for the year ended December 31, 2010 was primarily due to the strengthening of the Canadian dollar with respect to the US dollar and higher US dollar debt outstanding in 2010. In December 2009, the Corporation increased its senior secured term loan by US\$300 million. For the year ended December 31, 2010 the Canadian dollar strengthened against the US dollar by \$0.05 while in 2009 it strengthened by \$0.18.

RISK MANAGEMENT GAIN (LOSS)

	Year ended December 31	
(\$000)	2010	2009
Realized loss on interest rate swaps	(34,412)	(17,180)
Unrealized fair value gain on interest rate swaps	32,671	14,753
Amortization of unrealized loss on interest rate swaps from accumulated other comprehensive income	(20,041)	(7,676)
Total risk management (gain) loss	(21,782)	(10,103)

The Corporation realized an increase in interest costs due to the interest rate swaps which have been charged to operations as risk management loss. The Corporation hedged, until December 31, 2010, the interest rate on US\$700 million of its floating rate debt by swapping the London Interbank Offered Rate ("LIBOR") for an average fixed rate of 5.05%. For the year ended December 31, 2010 the average LIBOR rate was 0.35% compared to 0.89% for the year ended December 31, 2009.

The unrealized fair value gain on the interest rate swaps is due to the change in the fair value of the interest swaps. For the year ended December 31, 2010 the fair value of the interest rate swap liability decreased by \$32.7 million compared to \$14.8 million for the same period in 2009. The fair value of the interest rate swaps declined over the periods noted due to the shorter term to expiry of the contracts. As at December 31, 2010 the interest rate swap contracts have expired and there is no further liability associated with the contracts.

The amortization of the unrealized loss on interest rate swaps from accumulated other comprehensive income is a result of the Corporation previously applying hedge accounting to its interest rate swap contracts. Hedge accounting was subsequently discontinued as the hedges were no longer effective. As at December 31, 2010, all amounts remaining in accumulated other comprehensive income related to these swaps have been amortized into earnings.

INTEREST EXPENSE

	Year ended December 31	
(\$000)	2010	2009
Total interest expense	65,484	42,309
Capitalized to property, plant and equipment	(20,699)	(37,790)
Interest expense	44,785	4,519

Total interest expense in the year ended December 31, 2010 increased compared to 2009 primarily as a result of higher outstanding debt and higher interest rates on the Corporation's long-term debt. In December 2009 the Corporation increased its senior secured term loan by US\$300.0 million.

Effective December 1, 2009 the Corporation commenced planned principal operations and ceased capitalizing interest on the development of Phases 1 and 2 of the Christina Lake Project. Interest on the US\$300 million incremental portion of the senior secured term loan associated with the development of Phase 2B of the Christina Lake Project continues to be capitalized.

DEPLETION, DEPRECIATION AND ACCRETION

Depletion of the Christina Lake Project developed assets commenced December 1, 2009 and was calculated using the unit-of-production method based on total estimated proved reserves. This equated to \$15.76 per barrel of production for the year

ended December 31, 2010. Prior to December 2009, there was no depletion and depreciation expense related to Phases 1 and 2 of the Christina Lake Project as planned principal operations had not yet commenced.

INCOME TAXES

Future income tax expense for the year ended December 31, 2010 was \$9.6 million compared to a future income tax recovery of \$14.1 million in 2009.

The Corporation's effective income tax rate is primarily impacted by permanent differences and variances in valuation reserves. The significant permanent differences are:

- The non-taxable portion of capital foreign exchange gains and losses on the translation of the US dollar denominated debt. For the year ended December 31, 2010 the non-taxable foreign exchange gain was \$26.1 million compared to \$60.4 million for the year ended December 31, 2009.
- The non-taxable portion of stock-based compensation. For the year ended December 31, 2010, non-taxable stock-based compensation was \$14.4 million compared to \$12.9 million for the year ended December 31, 2009.

The Corporation is not currently taxable. As of December 31, 2010, the Corporation had approximately \$3.1 billion of available tax pools and had recognized a net future tax liability of \$22.2 million. In addition, at December 31, 2010 the Corporation had \$247.2 million of capital investment in respect of incomplete projects which will be added to available tax pools upon completion of the projects.

CAPITAL INVESTING

The following table summarizes the capital investments for the periods presented.

Summary of capital investment (\$000)	Year ended December 31	
	2010	2009
Christina Lake Project:		
Resource exploration & delineation	25,836	6,305
Horizontal drilling	36,910	6,867
Facilities, procurement & construction	241,621	255,328
Other	8,653	1,908
Total Christina Lake Project	313,020	270,408
Surmont and Growth Properties	15,253	1,812
Land and other acquisitions	100,961	136
Capitalized interest and fees	18,633	37,790
Other	36,728	33,729
Total cash investments	484,595	343,875
Non-cash investment	10,035	7,467
Total capital investment	494,630	351,342

During 2010, the Corporation invested cash totalling \$484.6 million compared with \$343.9 million in the same period in 2009. Capital investment in 2010 was focused on Christina Lake Project Phase 2B development and resource delineation at Christina Lake and the Growth Properties.

CHRISTINA LAKE PROJECT

During the year ended December 31, 2010 the Corporation drilled 66 core holes and six observation wells to assist in the determination of Phase 2B horizontal wells placement and further delineation of resources in the Christina Lake leases. The Phase 2B horizontal drilling program was initiated in the fourth quarter of 2010. Facilities investment in 2010 was directed towards Phase 2B detailed engineering and commencing the purchase of major equipment, installation of electric submersible pumps, and maintenance and reliability of the Phase 2 facility. As at December 31, 2010, the detailed engineering of Phase 2B was 41% complete and capital commitments for 90% of major equipment orders were in place. On November 30, 2010, the Corporation's board of directors approved the 35,000 bbls/d Phase 2B expansion with a cost estimate of \$1.4 billion.

Effective December 1, 2009 management determined that planned principal operations at Christina Lake had commenced. The Corporation therefore ceased capitalizing net operating and interest costs associated with Phases 1 and 2 as of December 1, 2009. Net operating costs for the 11 months ended November 30, 2009 totalled \$21.0 million and have been capitalized as they were incurred prior to the commencement of planned principal operations. (For further details, see the tables under the subheading "Operating Summary").

SURMONT AND GROWTH PROPERTIES

The Corporation invested \$15.3 million during the year ended December 31, 2010 to drill 24 core holes on the Growth Properties for increased resource definition and to evaluate source water quality near Surmont.

LAND AND OTHER ACQUISITIONS

During 2010 the Corporation invested \$42.5 million to purchase lands and assets associated with a tank farm construction project (the "Stonefell Terminal"), located east of the Access Pipeline Sturgeon Terminal. Once construction of the Stonefell Terminal is complete, it is anticipated to have a storage capacity of 900,000 barrels. The Corporation also acquired an additional 8,320 acres (13 square miles) of undeveloped oil sands leases in the Surmont area for \$54.9 million.

CAPITALIZED INTEREST AND FEES

The Corporation capitalizes interest expense and amortization of deferred finance charges for undeveloped property acquisitions and major development projects. Interest associated with the development of Phase 2B is being capitalized commencing December 1, 2009. During 2010, the Corporation capitalized \$18.6 million of interest and finance charges compared to \$37.8 million in 2009. Capitalization of interest for Phases 1 and 2 was discontinued effective December 1, 2009 due to the commencement of planned principal operations.

OTHER

Other capital investments include the costs to maintain the right to participate in a potential pipeline project, capitalized salaries and consulting costs and investment in leasehold improvements and tangible assets for the Corporation's offices.

NON-CASH

Non-cash capital investment is comprised of capitalized financing transaction costs, capitalized stock based-compensation and amounts capitalized in respect of asset retirement obligations.

SHARES OUTSTANDING

As at February 21, 2011, the Corporation had the following share capital instruments outstanding.

Common shares	190,497,231
Convertible securities	
Stock options outstanding – exercisable and unexercisable	12,310,995
Restricted share units outstanding – exercisable and unexercisable	404,945

OUTLOOK

The Corporation expects production volumes in 2011 to average between 25,000 and 27,000 barrels per day taking into account the anticipated plant turnaround in September 2011. Non-energy operating costs are budgeted to continue to trend downward with the guidance for 2011 being in the \$9 to \$11 per barrel range. Capital investment for 2011 is budgeted to be approximately \$900 million with the majority being invested towards MEG's strategic plan of growing bitumen production capacity to 260,000 barrels per day by 2020.

LIQUIDITY AND CAPITAL RESOURCES

The Corporation 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 development of Phase 2B is dependent on factors discussed in the "RISK FACTORS" section of this MD&A.

In addition to funding the capital investments described above, the Corporation anticipates that it will be required to maintain existing letters of credit and provide further letters of credit to support its operational and marketing activities. As at December 31, 2010, the Corporation had utilized US\$8.1 million of its US\$185.0 million revolving credit facility to support letters of credit. On February 10, 2011, the revolving credit facility was increased to US\$200 million.

As of December 31, 2010, the Corporation's capital resources included \$1.3 billion of working capital. Working capital is comprised of \$1.4 billion of cash, cash equivalents and short-term investments and a non-cash working capital deficiency of \$0.1 billion comprised of accounts receivable and inventories less accounts payable and accrued liabilities.

On August 6, 2010, the Corporation completed its initial public offering (the "IPO") and issued 20,000,000 common shares to the public for proceeds of \$663.5 million, being net of commissions and other costs relating to the issue aggregating \$36.5 million.

Other assets include \$13.4 million of floating rate notes received on the restructuring of Canadian non-bank commercial paper and US\$3.2 million of US Auction Rated Securities ("ARS"). The ARS were previously held in the Corporation's debt service reserve account and could not be liquidated due to the breakdown of the ARS market. Due to the illiquidity of these assets, the Corporation has classified them as a long-term investment. The investments are recorded at fair value determined on a discounted cash flow valuation using observable information regarding the timing of payments and the credit rating of the securities. These investments 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 operations in the period in which they arise. In May 2009, the Corporation received a \$1.0 million payment on these notes and has applied it against the estimated amounts to be recovered. As at December 31, 2010 an impairment provision of \$7.9 million has been recorded on the floating rate notes and ARS investments.

The Corporation's cash, cash equivalents and short-term investments are held in accounts with third party financial institutions and consist of invested cash and cash in the Corporation's operating accounts. The cash is invested in high grade liquid short term debt such as commercial and bank paper. To date, the Corporation has experienced no loss or lack of access to its cash in operating accounts, invested cash or cash equivalents other than the investment in the restructured floating rate notes and the ARS that were held in the debt service reserve. 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 accounts 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

	Year ended December 31	
(\$000)	2010	2009
Net cash provided by (used in)		
Operating activities	75,605	(60,204)
Investing activities	(474,546)	(427,168)
Financing activities	661,814	1,214,087
Foreign exchange losses on cash and cash equivalents held in foreign currency	(1,445)	(4,843)
Increase (decrease) in cash and cash equivalents	261,428	721,872

OPERATING ACTIVITIES

The Corporation was considered to be a development stage company until November 30, 2009 and cash flows for the first 11 months of 2009 were primarily comprised of financing activities net of investment made in the Corporation's development. Cash provided by or used in operations after November 30, 2009, also includes product and power sales net of operating expenses increasing net cash from operating activities by \$135.8 million over 2009.

Investing Activities

Net cash used for investing activities in the year ended December 31, 2010 increased by \$47.4 million compared to the year ended December 31, 2009. Cash used for capital investments during 2010 increased by \$140.7 million compared to 2009. Refer to the "CAPITAL INVESTING" section of this MD&A for further details.

Financing Activities

Financing activities for the year ended December 31, 2010 consisted of \$663.5 million in net proceeds from the Corporation's IPO and proceeds received from the exercise of stock options less principal payments on its long term debt. In 2009, the Corporation entered into standby purchase agreements with a number of parties. Pursuant to these agreements, provided that certain conditions were met, the Corporation had the right to require the parties to purchase common shares at a later date for a price of \$24.00 per share. In consideration for each standby commitment, the Corporation agreed to pay a standby fee equal to 7.5% of the commitment upon exercise of its right. The Corporation received \$976.0 million from exercising its rights under the standby purchase agreements to require the parties to purchase approximately 40.7 million common shares at a price of \$24.00 per share. The Corporation paid standby fees of \$73.2 million, equal to 7.5% of the commitment. All standby commitments have been exercised. Refer to the "TRANSACTIONS WITH RELATED PARTIES" section of this MD&A for further details.

On December 23, 2009 the Corporation reached an agreement to amend and extend the terms of its existing senior secured credit facilities. Under the terms of the agreement the Corporation's secured term loan was increased by US\$300 million and the

maturity date on US\$670 of the existing senior secured term loan was extended from April 3, 2013 to April 3, 2016. The Corporation contributed US\$97.8 million of the net proceeds from the increased borrowings to the debt service reserve to fund interest and principal payments through the fourth quarter of 2010. In conjunction with the amendments to its senior secured credit facilities, the Corporation established a US\$185 million revolving credit facility, which was subsequently amended to US\$200 million. The revolver matures on January 31, 2013.

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)	994,015	10,066	19,819	59,597	904,533
Interest on long-term debt(1)	295,083	57,890	111,590	111,590	14,013
Asset retirement obligation(2)	85,135	-	-	1,391	83,744
Contracts and purchase orders(3)	528,469	516,032	8,051	4,386	-
Operating leases(4)	41,145	4,031	8,062	8,091	20,961
	1,943,847	588,019	147,522	185,055	1,023,251

(1) This represents the scheduled principal repayment of the senior secured credit facility and associated interest payments based on interest rates in effect on December 31, 2010.

(2) This represents the undiscounted obligation associated with the retirement of the Corporation's oil and gas properties.

(3) This represents the future commitments associated with the construction of the Christina Lake Project Phase 2B facility, capital equipment maintenance and purchases, diluent purchases and horizontal well drilling rig.

(4) This represents the future commitments for the Calgary corporate office space.

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 Canadian GAAP. 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 financial statements.

Capital Assets

Crude oil and natural gas properties are accounted for in accordance with the Canadian Institute of Chartered Accountants ("CICA") guideline on full cost accounting in the oil and gas industry. Under this method, all costs, including internal costs and asset retirement costs, directly associated with the acquisition of, exploration for, and the development of crude oil and natural gas reserves, are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs, including estimated future development costs, are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves.

Capital assets are reviewed for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated future cash flows. If an impairment is identified, the assets are written down to the estimated fair market value. The calculation of these future cash flows is dependent on a number of estimates, including reserves, timing of

production, commodity prices, operating cost estimates and foreign exchange rates. As a result, future cash flow estimates are subject to significant management judgment.

The Corporation performed a cost center impairment test (ceiling test) at December 31, 2010 on its proved capital assets for oil and gas properties using undiscounted future cash flows from proved reserves based on forward indexed prices. The carrying value of these properties did not exceed the undiscounted cash flows.

Crude Oil 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 timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Corporation expects that over time its reserve estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization ("DD&A") and for determining potential asset impairment. For example, a revision to the proved reserve estimates would result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates may also result in an impairment of crude oil property, plant and equipment carrying amounts under the ceiling test.

Asset Retirement Obligation

The Corporation recognizes an asset and a liability for any existing asset retirement obligations, which are determined by estimating the fair value at the balance sheet date. This fair value is determined by estimating expected timing and cash flows that will be required for future dismantlement and site restoration, and then present valuing these future payments using a credit-adjusted risk free rate appropriate for the Corporation. 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 on the asset and accretion charged on the liability. Estimating the timing and amount of third party cash flows to settle this obligation is inherently difficult and is based on third party estimates and management's experience.

Income Taxes

The Corporation follows the liability method of accounting for income taxes. Under this method tax assets are recognized when it is more than likely realization will occur. Tax liabilities are recognized for temporary differences between recorded book values and underlying tax values. Rates used to determine asset and liability amounts are the rates in effect in the future periods when the timing differences change. The period in which timing differences reverse are impacted by future income and capital expenditures. Rates are also affected by legislation changes. These components can impact the changes to future income taxes.

Stock-based Compensation

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



Derivative Financial Instruments

The Corporation may utilize derivative financial instruments to manage 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 balance sheet date 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

During the year ended December 31, 2010 the Corporation did not have any related party transactions. In 2009 the Corporation had the following transactions with related parties:

- The Corporation entered into two standby purchase agreements with WPX Luxco, an affiliate of Warburg Pincus LLC, a New York limited liability company ("WP LLC"), which manages various entities that indirectly own entities that legally and/or beneficially owned more than 20% of the common shares of the Corporation and which had nominated three members of the Corporation's Board of Directors. Pursuant to the agreements, provided that certain conditions were met, the Corporation had the right to require WPX Luxco to purchase up to an aggregate of 13,246,398 common shares at a price of \$24.00 per share for an aggregate purchase price of approximately \$317.9 million. In consideration for each standby commitment, the Corporation agreed to pay WPX Luxco a fee equal to 7.5% of the standby commitment upon exercise of the Corporation's rights. The transactions were not considered to be in the normal course of operations and were measured at the exchange amount based on a \$24.00 price per share. The Corporation exercised its rights under the standby purchase agreements, and thereby received gross proceeds of \$317.9 million and paid WPX Luxco fees totalling \$23.8 million, equal to 7.5% of the commitments. As additional consideration for the first standby commitment, the Corporation entered into an Investor Rights Agreement between MEG and WPX Luxco dated May 15, 2009.
- The Corporation entered into two standby purchase agreements with CNOOC Belgium BVBA ("CNOOC"), a shareholder of the Corporation, which had nominated a member of the Corporation's Board of Directors. Pursuant to the agreements, provided that certain conditions were met, the Corporation had the right to require CNOOC to purchase up to an aggregate of 11,461,933 common shares at a price of \$24.00 per share for an aggregate purchase price of approximately \$275.1 million. In consideration for each standby commitment, the Corporation agreed to pay CNOOC a fee equal to 7.5% of the standby commitment upon exercise of the Corporation's rights. The transactions were not considered to be in the normal course of operations and were measured at the exchange amount based on a \$24.00 price per share. The Corporation exercised its rights under the standby purchase agreements, and thereby received gross proceeds of \$275.1 million and paid CNOOC fees totalling \$20.6 million, equal to 7.5% of the commitments.

These transactions were entered into in order to provide funding for the Corporation's capital program and the \$24.00 price per common share was considered to reflect the market value of the Corporation's shares at the time of the commitment.

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2010 and December 31, 2009, the Corporation did not have any off-balance sheet arrangements.

NEW ACCOUNTING POLICIES

There are no new accounting policies for the Corporation for the year ended December 31, 2010.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards ("IFRS")

In February 2008, the Canadian Accounting Standards Board confirmed that the use of IFRS will be required for interim and annual financial statements of publicly accountable enterprises effective for fiscal years beginning on or after January 1, 2011. Accordingly, the Corporation will commence reporting under IFRS for the period ended March 31, 2011. Comparative information for periods from the Corporation's transition date to IFRS of January 1, 2010 onwards will be restated to be in accordance with IFRS.

Transition to IFRS from Canadian GAAP

The Corporation has established a project plan and timeline for the implementation of IFRS which consists of three phases; initiation, detailed assessment and design and implementation.

In 2009 the Corporation completed the initiation phase which involved the completion of a high level review of the major differences between current Canadian GAAP and IFRS, the development of a timeline for addressing these differences in subsequent phases and an assessment of the impact on the Corporation's financial systems.

The Corporation has completed the detailed assessment and design phase of the project. The detailed assessment and design phase involved completing a comprehensive analysis of the impact of the IFRS differences identified in the initial scoping assessment. In addition, an evaluation of IFRS 1 "First-Time Adoption of International Financial Reporting Standards" which provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions, in certain areas, to the general requirement for full retrospective application of IFRS, has been performed.

In conjunction with the detailed assessment and design phase of the project the Corporation completed an assessment of its information systems and based on this review no significant changes to the information systems were required as part of the IFRS conversion process. In addition, the Corporation assessed its IFRS knowledge and ongoing education is being provided to the appropriate areas of the organization. The effects of existing IFRS on the Corporation's business activities and internal controls, including disclosure controls and procedures, have been reviewed and it is not expected that IFRS will result in any significant changes to the Corporation's business activities and internal control environment.

The Corporation has prepared draft financial statements and disclosures. Discussions with the Corporation's external auditors have been ongoing and will continue throughout the implementation phases. Regular reporting is provided to the Corporation's Audit Committee.

First-time adoption of IFRS

IFRS 1 generally requires that first-time adopters of IFRS retrospectively apply all IFRS standards with the exception of certain optional exemptions and mandatory exceptions. Set forth below are the IFRS 1 exemptions the Corporation expects to make in converting its Canadian GAAP financial statements to IFRS.

1. Deemed cost of property, plant and equipment – IFRS 1 allows an entity that followed full cost accounting under their previous GAAP to elect to measure oil and gas assets at deemed cost equal to the amounts determined under the entity's prior GAAP at the date of transition. Applying this exemption will result in the Corporation measuring both its exploration

and evaluation assets as well as assets in the development and production phase at the amounts determined under Canadian GAAP. The Corporation will test both exploration and evaluation assets and assets in the development and production phases for impairment as of the date of transition to IFRS, and if necessary, reduce the carrying amounts in accordance with IFRS.

2. Decommissioning liabilities included in the cost of property, plant and equipment – IFRS 1 allows entities which apply the deemed cost exemption for oil and gas assets to measure decommissioning, restoration or similar liabilities as at the date of transition to IFRS in accordance with IAS 37 and recognize directly in retained earnings any difference between that amount and the carrying amount of those liabilities determined under the entity's previous GAAP.
3. Share-based payments – IFRS 2 encourages application of its provisions to equity instruments granted on or before November 7, 2002, but permits the application only to equity instruments granted after November 7, 2002 that had not vested at the date of transition to IFRS. The Corporation expects to apply the exemption provided under IFRS 1 and will apply IFRS 2 to equity instruments granted after November 7, 2002 that had not vested as of January 1, 2010.
4. Business combinations – A first time adopter may elect not to apply IFRS 3 retrospectively to past business combinations. The Corporation will elect not to apply IFRS 3 retrospectively to business combinations occurring prior to the transition to IFRS.
5. Lease transactions – IFRS 1 allows a first time adopter of IFRS to apply the transitional provisions in IFRIC 4 in determining whether an arrangement contains a lease. The Corporation expects to apply these transitional provisions and will determine whether existing arrangements contain a lease on the basis of facts and circumstances existing at the transition date to IFRS.
6. Borrowing costs – First time adopters of IFRS may elect to apply the requirements of IAS 23 to borrowing costs relating to qualifying assets as of the date of transition to IFRS. The Corporation expects to utilize this IFRS 1 exemption and will apply the requirements of IAS 23 to borrowing costs relating to qualifying assets as of January 1, 2010.

IFRS 1 does not allow hindsight to be used to create or revise previous estimates. The estimates previously made by the Corporation under Canadian GAAP will not be revised for application of IFRS except where necessary to reflect a change resulting from differences in accounting policy.

Impact of adoption of IFRS on financial reporting

Based on the Corporation's evaluation to date and existing IFRS, the most significant impacts of IFRS conversion will be within the areas of property, plant and equipment, impairment of assets, provisions, share-based payments, financial instruments and income taxes. The effects and adjustments required to the Corporation's balance sheet as of January 1, 2010 are discussed below. The amounts disclosed are management's best estimates and are subject to change.



Property, Plant and Equipment ("PP&E")

IFRS does not prescribe specific oil and gas accounting guidance other than for costs associated with the exploration and evaluation phase. The Corporation currently follows full cost accounting as prescribed by Canadian GAAP and has identified the following significant differences:

- the treatment of pre-exploration costs,
- exploration and evaluation costs, and
- depletion, depreciation and amortization

Pre-exploration costs are costs incurred before the Corporation obtains the legal right to explore an area. Under Canadian full cost GAAP, these costs are capitalized, while under IFRS, these costs must be expensed. In 2010, these expenditures were not significant to the Corporation.

During the exploration and evaluation phase ("E&E"), the Corporation capitalizes costs incurred for these projects under Canadian GAAP. Under IFRS, the Corporation has the alternative to either continue capitalizing these costs until technical feasibility and commercial viability of the project has been determined, or expensing these costs as incurred. The Corporation will capitalize these costs until technical feasibility and commercial viability of the project has been determined. If technically feasible and commercially viable reserves are not established for a new area, the costs must be expensed.

Canadian GAAP prescribes that PP&E for producing oil and gas properties are depleted on a unit-of-production method using remaining proved reserves. IFRS provides the option of using either proved or proved plus probable reserves. The Corporation is currently evaluating these options.

As outlined above, IFRS 1 "First-time Adoption of International Financial Reporting Standards" includes a transition exemption for oil and gas companies following full cost accounting under their previous GAAP. The transition exemption allows full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes without requiring retroactive adjustment. The Corporation expects to adopt this exemption using the fair value of reserves as an allocation method.

As a result of these differences the Corporation estimates that \$1.1 billion in assets at January 1, 2010 will be removed from property, plant and equipment and included within intangible exploration and evaluation assets.

Impairment of Assets

Canadian GAAP generally uses a two-step approach to impairment testing: first comparing asset carrying values with undiscounted future cash flows to determine whether impairment exists; and then measuring any impairment by comparing asset carrying values with fair values. International Accounting Standard ("IAS") 36, "Impairment of Assets", uses a one-step approach for both testing for and measurement of impairment, with asset carrying values compared directly with the higher of fair value less costs to sell and value in use (which uses discounted future cash flows). This may result in more write-downs where carrying values of assets were previously supported under Canadian GAAP on an undiscounted cash flow basis, but could not be supported on a discounted cash flow basis. However, an impairment loss is reversed if there has been an increase in the estimated recoverable amount of a previously impaired asset. 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 depreciation or depletion, if

no impairment loss had been recognized. Canadian GAAP prohibits reversal of impairment losses. The Corporation does not expect that this difference will have a significant impact on the carrying value of assets upon transition to IFRS. However, this difference could significantly impact carrying amounts of assets and the results of operations in future periods.

Provisions (Including Asset Retirement Obligations)

IAS 37, "Provisions, Contingent Liabilities and Contingent Assets", requires a provision to be discounted using a current pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The timing and amount of future expenditures are reviewed regularly, together with the interest rate used in discounting the cash flows and the carrying amount of the provision is adjusted accordingly. Under Canadian GAAP a provision previously recognized is not revised for subsequent changes in interest rates. Also, for those provisions that are required to be discounted there is a difference in the rate applied as Canadian GAAP uses a credit-adjusted risk free rate while IAS 37 does not specify the use of a credit-adjusted risk free rate.

As discussed above, IFRS 1 includes a transition exemption for oil and gas companies following full cost accounting under their previous GAAP to value oil and gas assets at deemed cost. Entities applying this exemption are also allowed a transition exemption in determining decommissioning liabilities included in the cost of property, plant and equipment. The Corporation expects to apply this exemption and will measure its asset retirement obligations upon transition to IFRS in accordance with IAS 37 and will record the difference between that amount and the carrying amount of those liabilities under Canadian GAAP directly in retained earnings. The Corporation estimates that this change will result in a \$6.7 million increase in decommissioning provisions and a \$5.0 million increase in the deficit, net of \$1.7 million in deferred taxes, as at January 1, 2010.

Share-based Payments

IFRS 2, "Share-based Payments", requires each tranche of a share based award to be treated as a separate grant with a different vesting date and fair value. Under Canadian GAAP, share based awards are permitted to be valued using a pooled approach. In addition, IFRS does not permit the recognition of the expense associated with share-based payments to be recognized on a straight-line basis as is permitted under Canadian GAAP. The change in accounting policies related to share-based payments is estimated to result in an acceleration of expense recognition of \$6.7 million, thus increasing the deficit and contributed surplus balances as at January 1, 2010.

Financial Instruments

The Corporation's term loan D bears an interest rate floor of 300 basis points based on US prime and an interest rate floor of 200 basis points based on LIBOR. Under Canadian GAAP the economic characteristics and risks associated with the interest rate floor were considered to be closely related to the economic characteristics and risks associated with the host debt contract. Under IFRS these economic characteristics and risks are not considered to be closely related 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 considered an embedded derivative under IFRS and 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 profit or loss. The Corporation estimates that this change will result in a \$30.3 million decrease in the carrying value of long-term debt, the recognition of a \$28.0 million financial derivative liability and a \$1.7 million decrease in the deficit, net of \$0.6 million in deferred taxes, as at January 1, 2010.

Income Taxes

IAS 12, "Income Taxes", does not recognize a deferred tax liability or asset if it arises from initial recognition of an asset or liability outside a business combination and there is no impact in profit or loss at the time of the transaction. Also, the income tax

balances will be directly impacted by tax effects resulting from the changes required by some of the above IFRS accounting policy differences. The Corporation estimates that these differences will result in a cumulative decrease in the deferred tax liability of \$1.1 million as at January 1, 2010.

Under Canadian GAAP, the impact of deferred income taxes related to share issue costs are recognized directly in equity. Any subsequent changes affecting the deferred taxes in respect of the share issue costs are recognized in earnings. Under IFRS, deferred taxes recognized in respect of share issue costs are also recognized in equity. However, IAS 12 requires subsequent changes in the deferred tax expense recognized in respect of share issue costs to be recognized in equity. This change in accounting policy is expected to result in a re-classification between deficit and share capital at January 1, 2010 of \$1.1 million.

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. In addition to the risks categorized below, the Corporation is also subject to other risks and uncertainties which are described in the AIF under the headings "Regulatory Matters" and "Risk Factors."

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 and/or procurement performance falling below expected levels of output or efficiency;
- construction 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 or the Corporation's other future projects, 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 of recovering, transporting and processing hydrocarbons, such as fires, 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 prices;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher SORs;
- access to or an increase in the costs of diluents;
- an increase in the cost of natural gas;
- the reliability and maintenance of MEG's 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;
- the cost of chemicals used in MEG's operations, including in connection with water and/or oil treatment facilities; and
- the cost of compliance with applicable 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, programming, 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 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 and airstrips.

The failure 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 are 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 US dollars and prices of the Corporation's bitumen blend are generally based on US dollar market prices. Fluctuations in US 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 a Regional Plan for the Lower Athabasca Region (the "LARP"). There can be no assurance that the LARP or that 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 requirements 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.

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 company 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 company 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 company and have concluded that the Corporation's disclosure controls and procedures are effective at the financial year end of the company 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 Canadian GAAP. 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 company and concluded that the Corporation's internal controls over financial reporting is effective at the financial year end of the company for the foregoing purpose.

No material changes in the Corporation's internal controls over financial reporting were identified during the year ended December 31, 2010 that has 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.

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.

REPORT OF MANAGEMENT

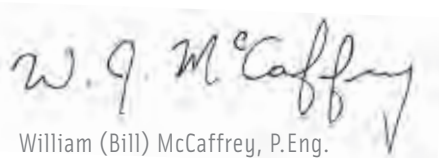
MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

The accompanying financial statements of MEG Energy Corp. (the "Corporation") are the responsibility of Management. The financial statements have been prepared by Management in Canadian dollars in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management's best judgments.

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 evaluation concluded that our internal controls over financial reporting were effective as of December 31, 2010.

The Corporation's Board of Directors has approved the information contained in the financial statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee, which is made up of four 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 financial statements and management's discussion and analysis prior to their release as well as annually to review the annual 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 financial statements as at December 31, 2010. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the financial statements.



William (Bill) McCaffrey, P.Eng.

Chairman, President and Chief Executive Officer



Dale J. Hohm, CA

Chief Financial Officer

February 23, 2011



AUDITOR'S REPORT TO THE SHAREHOLDERS

February 23, 2011

To the Shareholders of MEG Energy Corp.

We have audited the accompanying financial statements of MEG Energy Corp., which comprise the balance sheets as at December 31, 2010 and December 31, 2009 and the statements of operations and deficit, comprehensive income, accumulated other comprehensive loss and cash flows for the years then ended, and the related notes including a summary of significant accounting policies.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of 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 financial statements based on our audits. We conducted our audit 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the 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 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 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 financial statements present fairly, in all material respects, the financial position of MEG Energy Corp. as at December 31, 2010 and December 31, 2009 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

BALANCE SHEET

As at December 31 (\$ 000s)	2010	2009
Assets		
Current assets:		
Cash and cash equivalents (note 15)	\$ 1,224,446	\$ 963,018
Short-term investments	167,406	-
Accounts receivable and other (note 3)	96,964	33,662
Inventories (note 4)	6,173	5,560
Debt service reserve (note 5)	-	102,359
	1,494,989	1,104,599
Restricted cash (note 6)	-	12,810
Other assets (note 7)	7,492	7,743
Property, plant and equipment (note 8)	3,515,150	3,144,341
	\$ 5,017,631	\$ 4,269,493
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued payables	\$ 144,378	\$ 71,842
Current portion of deferred lease inducements (note 9)	292	-
Risk management liability (note 14)	-	32,671
Current portion of long-term debt (note 11)	10,065	10,593
	154,735	115,106
Deferred lease inducements (note 9)	3,185	-
Long-term debt (note 11)	969,933	1,029,687
Asset retirement obligations (note 10)	16,793	14,297
Future income tax liability (note 12)	22,238	14,290
	1,166,884	1,173,380
Commitments and contingencies (note 16)		
Shareholders' equity:		
Share capital (note 13)	3,821,579	3,137,696
Contributed surplus (note 13)	71,464	55,841
Deficit	(42,296)	(82,393)
Accumulated other comprehensive loss	-	(15,031)
	3,850,747	3,096,113
	\$ 5,017,631	\$ 4,269,493

See accompanying notes to financial statements.

On behalf of the Board:

(Signed)

William (Bill) McCaffrey, Director

(Signed)

Robert B. Hodgins, Director

STATEMENT OF OPERATIONS AND DEFICIT

Year ended December 31 (\$ 000s)	2010	2009
Revenues:		
Petroleum sales	\$ 717,610	\$ 21,380
Royalties	(16,521)	(573)
Power sales	29,197	2,615
Interest income	7,933	2,572
	738,219	25,994
Operating expenses:		
Operating costs	162,141	14,072
Cost of diluent	315,350	9,004
Transportation and selling costs	12,480	2,211
General and administrative	36,403	24,295
Stock-based compensation (note 13)	14,439	12,912
Research and development	5,384	4,690
Interest expense	44,785	4,519
Depletion, depreciation and accretion (notes 8 and 10)	124,801	3,103
	715,783	74,806
Revenues less operating expenses	22,436	(48,812)
Other (gain) loss:		
Foreign exchange gain, net	(49,055)	(120,107)
Risk management loss (note 14)	21,782	10,103
Loss on modification of long-term debt (note 11)	-	21,286
Change in fair value of other assets (note 7)	-	2,875
	(27,273)	(85,843)
Income before income taxes	49,709	37,031
Future income tax expense (recovery) (note 12)	9,612	(14,145)
Net income	40,097	51,176
Deficit, beginning of year	(82,393)	(133,569)
Deficit, end of year	\$ (42,296)	\$ (82,393)
Earnings per share (note 15)		
Basic	\$ 0.23	\$ 0.37
Diluted	\$ 0.22	\$ 0.36

See accompanying notes to financial statements.

STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31 (\$ 000s)	2010	2009
Net income	\$ 40,097	\$ 51,176
Other comprehensive income (loss), net of tax		
Gains (losses) on cash flow hedges (note 14)		
Unrealized gain on derivatives designated as cash flow hedges, net of taxes(1)	-	(1,532)
Realized loss on derivatives designated as cash flow hedges capitalized, net of taxes(2)	-	12,226
Amortization of balance in AOCI(3)	15,031	5,757
Other comprehensive income	15,031	16,451
Total comprehensive income	\$ 55,128	\$ 67,627

STATEMENT OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Year ended December 31 (\$ 000s)	2010	2009
Balance, beginning of year	\$ (15,031)	\$ (31,482)
Other comprehensive income, net of taxes	15,031	16,451
Balance, at end of year	\$ -	\$ (15,031)

(1) Net income tax expense, year ended December 31, 2010 - nil (year ended December 31, 2009 - \$511 benefit)

(2) Net income tax expense, year ended December 31, 2010 - nil (year ended December 31, 2009 - \$4,075)

(3) Net income tax expense, year ended December 31, 2010 - \$5,010 (year ended December 31, 2009 -1,919)

See accompanying notes to financial statements.

STATEMENT OF CASH FLOWS

Year ended December 31 (\$ 000s)	2010	2009
Cash provided by (used in):		
Operations:		
Net income	\$ 40,097	\$ 51,176
Items not involving cash:		
Stock-based compensation	14,439	12,912
Depletion, depreciation and accretion	124,801	3,103
Unrealized net gain on foreign exchange	(50,741)	(122,415)
Unrealized gain on risk management	(12,630)	(7,077)
Loss on modification of long-term debt	-	11,009
Future income tax expense (recovery)	9,612	(14,145)
Other	170	3,211
Net change in non-cash operating working capital items (note 15)	(50,143)	2,022
	75,605	(60,204)
Investing:		
Purchase of property, plant and equipment	(484,595)	(343,875)
Lease inducement (note 9)	3,501	-
Change in debt service reserve	102,359	(50,146)
Decrease (increase) in restricted cash (note 6)	12,810	(12,810)
Payments received on commercial paper and other	21	1,061
Net change in non-cash investing working capital items (note 15)	(108,642)	(21,398)
	(474,546)	(427,168)
Financing:		
Issue of shares	672,170	889,922
Issue of long-term debt	-	332,945
Repayment of long-term debt	(10,356)	(8,780)
	661,814	1,214,087
Foreign exchange loss on cash and cash equivalents held in foreign currency	(1,445)	(4,843)
Increase in cash	261,428	721,872
Cash and cash equivalents, beginning of year (note 15)	963,018	241,146
Cash and cash equivalents, end of year (note 15)	\$ 1,224,446	\$ 963,018
Cash interest paid	\$ 97,636	\$ 60,172

See accompanying notes to financial statements.

NOTES TO FINANCIAL STATEMENTS

Year ended December 31, 2010. Tabular amounts are expressed in \$ 000s unless otherwise noted.

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 850 sections of oil sands leases in the Athabasca region of northern Alberta and is primarily engaged in a steam assisted gravity drainage ("SAGD") 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 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.

1. SIGNIFICANT ACCOUNTING POLICIES:

(a) Basis of presentation:

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and reflect the policies described below. Unless otherwise stated, all dollars are expressed in Canadian dollars.

(b) Revenue and royalty recognition - oil and gas products:

Revenue associated with the sale of 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.

(c) Revenue recognition - power sales:

Revenue from power generated in excess of internal requirements is recognized when the power leaves the plant gate at which point the risks and rewards are transferred to the customer.

(d) Transportation and selling costs:

Transportation and selling costs include the Corporation's cost of operating the Access Pipeline and other transportation and selling costs and are recognized as the related product is sold.

(e) Cash and cash equivalents:

Cash and cash equivalents include short-term investments such as commercial paper, money market deposits or similar instruments, with a maturity of three months or less when purchased.

(f) Short-term investments:

Short-term investments consist of commercial paper, money market deposits or similar instruments with a maturity of between 91 and 180 days from the date of purchase.

(g) Deposits and advances:

Deposits and advances 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.

(h) 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.

(i) Leases:

Operating leases and leasing costs are expensed as incurred. Leasehold incentives are amortized on a straight line basis over the term of the lease.

(j) Foreign currency translation:

Transactions in foreign currencies are translated into Canadian dollars at exchange rates prevailing at the transaction dates. 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. Exchange gains and losses resulting from operating activities are included in earnings.

(k) Financing transaction costs:

The Corporation capitalizes the carrying costs, including interest and financing transaction costs on long-term debt and the debt service reserve, for undeveloped property acquisitions and major development projects. Financing transaction costs associated with the issuance of long-term debt are included as a component of the debt value and are amortized over the life of the debt utilizing the effective interest rate method.

(l) Asset retirement obligations:

The fair value of estimated asset retirement obligations are recognized in the financial statements as incurred. Fair value is defined as the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale. Asset retirement obligations include those legal obligations whereby the Corporation will be required to retire tangible long-lived assets such as producing well sites, plants and pipelines. The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related long-lived asset and allocated to expense on a basis consistent with depreciation and depletion. Asset retirement obligations are accreted to the future value over the life of the obligations. Actual expenditures incurred are charged against the accumulated obligation.

(m) Property, plant and equipment:

(i) Crude oil and natural gas properties and equipment

The Corporation follows the full cost method of accounting for crude oil and natural gas properties and related equipment. All costs related to the acquisition of, exploration for and development of crude oil and natural gas reserves are capitalized on a country-by-country cost centre basis. Such costs include land acquisition costs, geological and geophysical costs, carrying charges of non-producing property, costs of drilling both productive and non-productive wells, production equipment, pipeline equipment and overhead charges related to exploration and development activities. Proceeds from the disposition of oil and gas properties are credited to the capitalized costs except for dispositions which would significantly alter the rate of depletion and depreciation, in which case a gain or loss would be recorded.

Operating costs net of revenues in relation to major development projects that are not ready for their intended use are capitalized. Once the assets are considered ready for their intended use, revenue is recognized and operating costs, including depletion, are recorded in earnings.

Effective December 1, 2009 planned principal operations associated with Phases 1 and 2 of the Corporation's Christina Lake Project commenced and revenues and operating costs have been recognized in the Statement of Operations and Deficit. Prior to the commencement of planned principal operations, all revenues and expenses relating to the Corporation's first development project were capitalized.

Capitalized costs in each cost centre, together with estimated future capital costs associated with proven reserves, are depleted and depreciated using the unit-of-production method based on gross proven reserves of petroleum and natural gas as determined by engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content. Costs of significant unproved properties and major development projects are excluded from the depletion and depreciation calculation.

The Corporation annually conducts a cost centre impairment test (ceiling test) that requires cost centres to be tested for recoverability using undiscounted future cash flows from proved reserves which are determined using forward indexed prices. When the carrying amount of a cost centre is not recoverable, the cost centre would be written down to its fair value. Fair value is estimated using accepted present value techniques when determining expected cash flows. The cost of unproved properties and major development projects are excluded from the ceiling test calculation and subject to a separate impairment test. In circumstances of impairment, the impairment would be calculated as the amount by which the carrying amounts exceed the net present value of future cash flows. The cost of any unproved property or major development project that is considered to be impaired is included in the costs subject to depletion.

(ii) Pipeline transportation equipment

Pipeline transportation equipment is depreciated using the unit-of-production method based on the Corporation's gross proven reserves of petroleum and natural gas that are served by the pipeline. The cost of line fill for the pipeline is excluded from the depreciation calculation.

(iii) Office equipment

Office equipment is stated at cost less accumulated depreciation. Depreciation is provided over the useful life of the assets on the declining balance basis at 25%.

(iv) Leasehold improvements

Leasehold improvements are depreciated on a straight line basis over the term of the lease.

(n) Stock-based compensation:

The Corporation records compensation cost for stock options granted to employees, directors and consultants using the fair value method. Fair values are determined using the Black-Scholes option pricing model. Compensation costs are recognized over the vesting period.

(o) Restricted share units ("RSUs"):

The Corporation records compensation cost for RSUs granted to employees, directors and consultants using the fair value method. Fair value is determined based on the share price of the Corporation's common shares on the date of grant with the resulting expense recognized in earnings over the vesting period.

(p) Use of estimates and measurement uncertainty:

The timely preparation of the financial statements in conformity with Canadian GAAP requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities at the date of the 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 financial statements. Accordingly, actual results may differ materially from estimated amounts as future confirming events occur.

Estimates of the stage of completion of capital projects at the financial statement date affect the calculation of additions to property, plant and equipment and the related accrued liability. In addition, estimates regarding the timing of when major development projects are ready for their planned use affect the amounts recorded in property and equipment or recognized in earnings.

Amounts recorded for depreciation, depletion and accretion, asset retirement costs and obligations, amounts used for ceiling test and impairment calculations and amounts used in the determination of future taxes are based on estimates of petroleum, natural gas and bitumen reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs and the related future cash flows are subject to measurement uncertainty, and the impact in the Financial Statements of future periods could be material.

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, those amounts are subject to measurement uncertainty.

Amounts recorded for other assets are determined based on valuation models where the significant inputs are based on available information for similar securities and information regarding the specific assets held, which may not be indicative of the value of the actual securities held by the corporation. As such, these amounts are subject to measurement uncertainty.

The estimated fair value of the Corporation's financial assets and liabilities, are by their very nature, subject to measurement uncertainty.

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

(q) 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.

(r) Future income taxes:

The Corporation uses the liability method of tax allocation accounting. Under the liability method, the difference between tax basis of an asset or liability and its financial reporting basis is computed and measured using substantively enacted tax rates in the period in which the temporary differences are expected to be realized or settled. If there is uncertainty in the realization of a tax asset, a valuation allowance reduces or eliminates the tax asset that is recorded.

(s) 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. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are marked-to-market whereby instruments are recorded in the balance sheet as either an asset or liability with changes in fair value recognized in net earnings. Changes in fair value of derivative financial instruments designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Any change in fair value related to an ineffective hedge is immediately recognized in earnings. The effectiveness of the hedging relationship is evaluated at the inception of the hedge and on an ongoing basis.

2. FUTURE ACCOUNTING CHANGES:

International Financial Reporting Standards:

In February 2008, the Canadian Accounting Standards Board confirmed that the use of International Financial Reporting Standards ("IFRS") will be required for interim and annual financial statements of publicly accountable profit-oriented enterprises effective for fiscal years beginning on or after January 1, 2011. As such, the Corporation will be required to report using IFRS beginning January 1, 2011. The transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for its year ended December 31, 2010, and of the opening balance sheet as at January 1, 2010.

3. ACCOUNTS RECEIVABLE AND OTHER:

	2010		2009	
Accounts receivable	\$	94,170	\$	28,524
Deposits and advances		2,794		5,138
	\$	96,964	\$	33,662

4. INVENTORIES:

During the year ended December 31, 2010 a total of \$315.4 million (2009 – \$9.0 million) in inventory product costs were charged to earnings through cost of diluent. During the year ended December 31, 2009, a total of \$29.2 million was capitalized to property, plant and equipment.

5. DEBT SERVICE RESERVE:

Until December 31, 2010, investments were required to be held in a US dollar debt service reserve account to fund interest and principal payments associated with the senior secured credit facilities. As of December 31, 2010 the Corporation is no longer required to maintain a debt service reserve account.

The US dollar denominated debt service account has been translated into Canadian dollars at the period end exchange rate. The foreign exchange loss on the debt service reserve was \$2.0 million for the year ended December 31, 2010 (December 31, 2009 – \$3.4 million), and has been recognized in operations through foreign exchange.

6. RESTRICTED CASH:

Restricted cash consisted of cash on deposit to collateralize letters of credit issued by the Corporation. In the second quarter of 2010, letters of credit previously issued were cancelled and replaced by letters of credit issued under the Corporation's US\$185 million revolving credit facility (note 11).

7. OTHER ASSETS:

		2010		2009
MAV Notes (formerly asset-backed commercial paper)(a)	\$	4,707	\$	4,769
US Auction Rate Securities(b)		2,785		2,974
	\$	7,492	\$	7,743

(a) An investment of \$13.4 million in certain Canadian non-bank asset-backed commercial paper was not repaid on maturity in 2007 due to liquidity problems affecting the issuers of the commercial paper and has been classified as a long-term asset. The proposal to restructure the commercial paper into floating rate notes whose maturity is to match the underlying assets was approved and implemented on January 21, 2009. The Corporation has received \$13.4 million of floating rate Master Asset Vehicle ("MAV") notes that mature between June 30, 2013 and July 15, 2056; \$4.2 million in 2013, \$0.6 million in 2014, \$8.3 million in 2016, \$0.1 million in 2029 and \$0.2 million in 2056. The replacement notes 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 operations in the period in which they arise. The Corporation is uncertain as to the amount that will ultimately be recovered from these notes as there is not an active market. Based on the information that is available, the Corporation has applied a discounted cash flow valuation to the notes and they have been recorded at 35% of their maturity value. In May 2009 the Corporation received a \$1.0 million payment on these notes and has applied it against the estimated amounts to be recovered. As at December 31, 2010, the total impairment provision on the notes was \$7.6 million (2009 - \$7.6 million).

(b) A US\$3.2 million investment in US Auction Rate Securities (ARS), held in the Corporation's debt service reserve account, was not sold due to liquidity issues within the ARS market. The Corporation continues to earn interest on the ARS at the specified contract rate and has received all scheduled principal repayments to-date. However, due to the illiquidity of the investment the Corporation has classified the ARS as a long-term investment. The investment is recorded at fair value determined based on a discounted cash flow valuation using observable information regarding the timing of payments and credit rating of the securities. As at December 31, 2010, an impairment provision of \$0.4 million (2009 - \$0.4 million) has been recorded on the investment. The unrealized foreign exchange loss on the investments was \$0.2 million for the year ended December 31, 2010 (December 31, 2009 - \$0.6 million) and has been reflected in the statement of operations through foreign exchange gain (loss).

8. PROPERTY, PLANT AND EQUIPMENT:

December 31, 2010	Cost	Accumulated depletion and depreciation	Net book value
Oil sands properties and equipment	\$ 3,624,092	\$ 125,839	\$ 3,498,253
Corporate assets	18,647	1,750	16,897
	\$ 3,642,739	\$ 127,589	\$ 3,515,150

December 31, 2009	Cost	Accumulated depletion and depreciation	Net book value
Oil sands properties and equipment	\$ 3,144,945	\$ 3,270	\$ 3,141,675
Corporate assets	4,155	1,489	2,666
	\$ 3,149,100	\$ 4,759	\$ 3,144,341

Effective December 1, 2009, planned principal operations of the Corporation's Christina Lake Project commenced and the Corporation began depleting the developed oil sands properties and equipment costs, excluding pipeline line fill costs of \$40.2 million. Prior to the commencement of principal operations, operating costs, net of revenues, were capitalized. The cost of undeveloped properties not subject to depletion as at December 31, 2010 was \$1,334.2 million (2009 – \$1,194.6 million).

In 2010, the Corporation capitalized \$11.3 million (2009 – \$9.6 million) of general and administrative expenses, \$3.7 million (2009 – \$3.8 million) of stock-based compensation costs and \$20.7 million (2009 – \$40.1 million) of interest and debt service costs relating to oil sands exploration and development activities.

The pricing assumptions used in the ceiling test evaluation of the Corporation's bitumen reserves as at December 31, 2010 are presented in the table below. The prices are based on the Corporation's 2010 reserve report prepared by GLJ Petroleum Consultants Ltd. Based on the ceiling test and other assessments, no impairment has been recorded at December 31, 2010.

	Bitumen Wellhead Current (\$CDN/bbl)	WTI @ Cushing (\$US/bbl)
2011	\$ 61.02	\$ 88.00
2012	61.14	89.00
2013	60.35	90.00
2014	62.13	92.00
2015	64.50	95.17
	Approximately 2% thereafter	Approximately 2% thereafter

9. DEFERRED LEASE INDUCEMENTS:

Lease inducements applicable to lease contracts are deferred and amortized as a reduction of general and administrative costs on a straight-line basis over the lease term.

As at December 31	2010
Deferred lease inducements, beginning of year	\$ -
Additions	3,501
Amortization of deferred lease inducements	(24)
Deferred lease inducements, end of year	\$ 3,477
Less current portion of deferred lease inducements	(292)
Non-current portion of deferred lease inducements	\$ 3,185

10. ASSET RETIREMENT OBLIGATIONS:

The following table presents the obligation associated with the retirement of oil sands properties:

	2010	2009
Asset retirement obligations, beginning of year	\$ 14,297	\$ 12,907
Liabilities incurred	1,746	570
Liabilities settled	(299)	(75)
Accretion	1,049	895
Asset retirement obligations, end of year	\$ 16,793	\$ 14,297

The estimated future undiscounted asset retirement obligation as at December 31, 2010 is \$85.1 million (2009 – \$80.2 million), which has been discounted using an average credit-adjusted risk-free rate of 6.32%. This obligation is estimated to be settled in periods up to 2057.

11. LONG-TERM DEBT:

	2010	2009
Senior secured term loan B (US\$41.5 million; 2009-US\$41.9 million)(a)	\$ 41,240	\$ 43,836
Senior secured term loan D (US\$957.9 million; 2009-US\$967.6 million)(a)	952,775	1,012,741
Financing transaction costs(b)	(14,017)	(16,297)
	979,998	1,040,280
Less current portion of senior secured term loan B	(417)	(439)
Less current portion of senior secured term loan D	(9,648)	(10,154)
	\$ 969,933	\$ 1,029,687

- (a) The Corporation's senior secured credit facilities are comprised of US\$999.4 million in term loans and a three year US\$185 million revolving credit facility. The US\$41.5 million term loan B matures on April 3, 2013 and the US\$957.9 million term loan D matures on April 3, 2016. The term loan B bears a floating interest rate based on either US prime or the London Interbank Offered Rate ("LIBOR"), at the Corporation's option, plus a credit spread of 100 or 200 basis points, respectively. The term loan D bears a floating interest rate based on either US prime or LIBOR, at the Corporation's option, plus a credit spread of 300 or 400 basis points, respectively. In addition, the term loan D bears an interest rate floor of 325 basis points based on US prime and an interest rate floor of 200 basis points based on LIBOR. The effective interest rate on the Corporation's long-term debt was 6.3% for the year ended December 31, 2010 (2009 – 7.0%). As at December 31, 2010, \$8.3 million of the revolving credit facility was utilized to support letters of credit. As at December 31, 2009, no amount had been drawn under the revolving credit facility.

The US dollar denominated debt is translated into Canadian dollars at the period end exchange rate of \$1 US = \$0.9946 CDN (December 31, 2009 – \$1 US = \$1.0466 CDN). The unrealized foreign exchange gain on the senior secured term loan was \$52.2 million for the year ended December 31, 2010 (2009 – \$127.3 million gain) and has been recognized in earnings through foreign exchange.

The credit facilities contain certain provisions which restrict the Corporation's ability to incur additional indebtedness, pay dividends, make certain payments, dispose of interests in the project or change the nature of the Corporation's business. The credit facility provides the lenders with security over all the assets of the Corporation.

Required debt principal repayments are as follows:	
2011	10,065
2012	10,065
2013	49,949
2014	9,648
2015	9,648
Thereafter	904,640

- (b) During the year ended December 31, 2010, \$2.1 million (2009 – \$2.3 million) of financing transaction costs related to senior secured credit facilities were capitalized to property, plant and equipment in accordance with the Corporation's policy for capitalizing financing costs for major development projects while \$0.2 million (2009 – \$0.6 million) was charged to earnings through interest expense.

12. INCOME TAXES:

The income tax provisions differ from results which would be obtained had the Corporation applied the combined federal and provincial statutory rates of 28.0% (2009 – 29.0%) to earnings. The reasons for these differences are as follows:

	2010	2009
Expected income tax expense	\$ 13,918	\$ 10,739
Add (deduct) the effect of:		
Stock-based compensation	4,043	3,744
Non-taxable gain on foreign exchange	(7,308)	(17,525)
Other	(1,041)	2,620
Change in valuation allowance	-	(13,723)
	\$ 9,612	\$ (14,145)

The components of the net future income tax liability at December 31 are as follows:

	2010	2009
Future income tax liability:		
Capital assets in excess of tax values	\$ 436,032	\$ 370,035
Future income tax assets:		
Share and debt issue costs	(14,174)	(14,066)
Non-capital loss carried forward	(396,691)	(330,793)
Risk management liability	-	(8,168)
Other	(2,929)	(2,718)
Net future income tax liability	\$ 22,238	\$ 14,290

At December 31, 2010, the Corporation has approximately \$3,145.5 million of available tax pools (2009 – \$2,911.4 million). Included in the tax pools are \$1,586.8 million of non capital loss carry forward balances (\$212.7 million expiring in 2026; \$253.9 million expiring in 2027; \$341.4 million expiring in 2028; \$528.7 million expiring in 2029; and \$250.1 million expiring in 2030). In addition, at December 31, 2010 the Corporation had an additional \$247.2 million (2009 – \$88.9 million) of capital investment in incomplete projects which will be added to available tax pools upon completion of the projects.

13. SHARE CAPITAL:

(a) Authorized:

Unlimited number of common shares

Unlimited number of preferred shares

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

	2010		2009	
	Number of shares	Amount	Number of shares	Amount
Balance, beginning of year	169,130,053	\$ 3,137,696	128,123,287	\$2,243,618
Stock options exercised	745,098	11,406	341,017	2,387
Shares issued for cash	20,000,000	700,000	40,665,749	975,978
Share issue costs, net of taxes of \$9,174 (2009 – \$3,698)		(27,523)		(84,287)
Balance, end of year	189,875,151	\$ 3,821,579	169,130,053	\$3,137,696

During the year ended December 31, 2010, a total of 745,098 stock options were exercised at a weighted average price of \$11.90 per share.

On August 6, 2010, pursuant to an underwriting agreement and a prospectus each dated July 28, 2010, the Corporation completed its initial public offering and issued 20,000,000 common shares to the public at a price of \$35.00 per share.

During the year ended December 31, 2009, the Corporation issued 40,665,749 common shares at a price of \$24.00 per share and 341,017 stock options were exercised at a weighted average exercise price of \$5.65 per share.

(c) Stock options:

Effective June 9, 2010, the Corporation's Board of Directors approved a new option plan ("the 2010 Option Plan") as a replacement for the Corporation's existing stock option plan ("2003 Option Plan"). The 2010 Option Plan allows for the granting of options to directors, officers, employees and consultants of the Corporation. Options granted under the 2010 Option Plan are generally fully exercisable after three years and expire seven years after the grant date. Prior to June 9, 2010, the Corporation issued options to employees and directors under a previous option plan and under stand alone option agreements (collectively, the "Old Option Plan"). No additional options will be granted under the Old Option Plan. The Corporation has reserved 18,987,515 common shares (10% of the outstanding common shares, subject to certain restrictions) for issuance pursuant to the Old Option Plan, the 2010 Option Plan and the restricted share unit plan ("the RSU Plan").

	2010		2009	
	Stock options	Weighted average exercise price per share	Stock options	Weighted average exercise price per share
Balance, beginning of year	12,609,407	\$ 19.89	10,892,674	\$ 18.86
Granted	1,208,170	33.48	2,206,500	24.00
Forfeited	(152,633)	29.35	(148,750)	38.24
Exercised	(745,098)	11.90	(341,017)	5.65
Balance, end of year	12,919,846	\$ 21.51	12,609,407	\$ 19.89

		Outstanding		Vested	
Range of exercise prices	Options	Weighted average exercise price	Weighted average remaining life	Options	Weighted average exercise price
\$1.00 - \$2.15	262,087	\$1.44	2.0	262,087	\$1.44
\$2.16 - \$5.00	2,702,505	4.53	2.1	2,702,505	4.53
\$5.01 - \$7.00	1,858,394	7.00	2.1	1,858,394	7.00
\$7.01 - \$11.00	826,402	11.00	2.1	826,402	11.00
\$11.01 - \$24.00	2,093,340	24.00	5.6	983,590	24.00
\$24.01 - \$33.50	965,700	28.02	2.7	965,700	28.02
\$33.51 - \$41.00	4,211,418	39.40	4.6	2,993,873	40.98
	12,919,846	\$21.51	3.5	10,592,551	\$19.64

Effective January 1, 2010, the Corporation's Board of Directors approved an extension of the expiry date of all outstanding options to acquire common shares in the Corporation under existing stock option agreements with an expiry date earlier than January 1, 2013 such that the new expiry date for all such outstanding options is January 31, 2013. The Black-Scholes value of extending these stock options was \$1.1 million.

The fair value of each option granted is estimated on the date of the grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

Risk free rate	2.34%
Expected lives	5 years
Volatility	36%
Annual dividend per share	\$ nil
Fair value of options granted	\$ 12.27

(d) Restricted share units:

Effective June 9, 2010, the Corporation's Board of Directors approved the RSU Plan. The RSU Plan allows for the granting of Restricted Share Units ("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. The value of an RSU is determined based on the share price of the Corporation's common shares on the date of grant with the resulting expense recognized in stock-based compensation expense over the three year vesting term.

RSUs	2010
Balance, beginning of year	-
Granted	407,610
Forfeited	(2,665)
Balance, end of year	404,945

(e) Contributed surplus:

	2010	2009
Balance, beginning of year	\$ 55,841	\$ 39,614
Stock-based compensation - expensed	14,439	12,912
Stock-based compensation - capitalized	3,723	3,775
Stock options exercised	(2,539)	(460)
Balance, end of year	\$ 71,464	\$ 55,841

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT:

The financial instruments recognized in the balance sheet are comprised of cash and cash equivalents, short-term investments, accounts receivable, other assets, debt service reserve, restricted cash, risk management activities, accounts payable and accrued liabilities, and long-term debt. As at December 31, 2010 cash and cash equivalents, short-term investments, other assets, debt service reserve, restricted cash and risk management liability were classified as held-for-trading financial instruments, accounts receivable were classified as loans and receivables and accounts payable and accrued liabilities were classified as other financial liabilities. Long-term debt was carried at amortized cost.

(a) Fair value measurements:

The carrying value of cash and cash equivalents, short-term investments, accounts receivable, debt service reserve, restricted cash and accounts payable and accrued liabilities included in the balance sheet approximate the fair value of the respective assets and liabilities due to the short term nature of those instruments. The fair value measurement information for other assets, risk management and long-term debt is noted below.



			Fair value measurements using		
			Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
2010	Carrying amount	Fair value			
Financial assets					
Other assets	\$ 7,492	\$ 7,492	\$ -	\$ -	\$ 7,492
Financial liabilities					
Risk management liability	-	-	-	-	-
Long-term debt	979,998	921,198	-	921,198	-

			Fair value measurements using		
			Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
2009	Carrying amount	Fair value			
Financial assets					
Other assets	\$ 7,743	\$ 7,743	\$ -	\$ -	\$ 7,743
Financial liabilities					
Risk management liability	32,671	32,671	-	32,671	-
Long-term debt	1,040,280	1,019,474	-	1,019,474	-

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

As at December 31, 2010 the Corporation did not have any assets or liabilities whose fair values were derived using Level 1 inputs.

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

Risk management liability and long-term debt – The fair value of the risk management liability and long-term debt are derived from quoted prices from financial institutions for the Corporation's interest rate swaps and long-term debt respectively.

Level 3 fair value measurements are based on unobservable information.

Other assets – Other assets are comprised of investments in asset backed commercial paper that was restructured into Master Asset Vehicle (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. Impairment losses of \$nil for the year ended December 31, 2010 (2009 – \$2.9 million) have been included in income in decrease in fair value of other assets.

(b) Foreign exchange risk:

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the Corporation's operating and financial results. The Corporation had a US dollar denominated debt service reserve account and has US dollar denominated long-term debt as described in notes 5 and 11 respectively. As at December 31, 2010, a \$0.01 change in the US to Canadian dollar exchange rate would have resulted in a corresponding change in the carrying value of long-term debt of \$9.9 million (2009 - \$9.1 million).

(c) Interest rate risk:

The Corporation is exposed to interest rate risk in relation to interest income earned on cash and cash equivalents, short-term investments, debt service reserve, restricted cash and other assets. During the year ended December 31, 2010, a 1% increase in interest rates earned on these financial instruments would have resulted in an increase in net earnings of \$8.2 million (2009 - \$2.4 million). A 1% decrease in interest rates earned would have resulted in a decrease in net earnings of \$5.9 million (2009 - \$1.9 million).

The Corporation is also exposed to interest rate risk in relation to the interest expense on its floating rate long-term debt. To mitigate a portion of the risk of interest rate increases on long-term debt, the Corporation had entered into interest rate swap contracts to fix the interest rate on US\$700 million of the US\$999.4 million total debt. These contracts expired at the end of December 2010. As of December 23, 2009, the majority of the Corporation's long-term debt has an interest rate floor. Excluding the impact of the interest swaps and the interest rate floor, a 1% change in the LIBOR rate would have resulted in an increase/decrease in interest expense, after capitalization of interest, of \$7.3 million for the year ended December 31, 2010 (2009 - \$0.7 million).

The Corporation had two counterparties to the interest rate swap contracts which were originally designated as cash flow hedges and recorded at fair value. Effective October 1, 2008 and December 23, 2009 the Corporation discontinued applying hedge accounting to these interest rate swap contracts as they were no longer effective. The effective portion of the change in fair value was recognized in Other Comprehensive Income. Any gain or loss in fair value relating to the ineffective portion was recognized immediately in the statement of earnings. The change in the fair value of the related contracts was recognized in earnings. As at December 31, 2010 no amounts remain in accumulated other comprehensive income related to these swaps.

	2010	2009
Risk management liability, beginning of year	\$ 32,671	\$ 61,683
Decrease in liability fair value recognized in earnings	(32,671)	(14,753)
Decrease in liability fair value recognized in OCI	-	(14,259)
Risk management liability, end of year	-	32,671
Risk management expense	2010	2009
Realized loss on interest rate swaps	\$ 34,412	\$ 17,180
Unrealized fair value gain on interest rate swaps	(32,671)	(14,753)
Amortization of unrealized loss on interest rate swaps from AOCI	20,041	7,676
	\$ 21,782	\$ 10,103

(d) Commodity price risk:

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 diluents which are all inputs into the SAGD production and transportation process.

Surplus power from the 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:

A substantial portion of accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risk. At December 31, 2010, the Corporation's estimated maximum exposure to credit risk related to customer and joint venture receivables was \$94.2 million, there were no significant amounts which were past due as at December 31, 2010. Purchasers of petroleum and natural gas are subject to an internal credit review to reduce the risk of non-payment.

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 balances at December 31, 2010 was \$1,391.9 million. None of the investments are past their maturity or considered impaired. The Corporation's estimated maximum exposure to credit risk related to its cash, cash equivalents and short-term investments is \$1,391.9 million.

The Corporation's investments in MAV Notes and US Auction Rate Securities are subject to the credit risk associated with the counterparties to the investments. A \$7.6 million reduction in the value of the MAV Notes and a \$0.4 million reduction in the value of the ARS were recognized in 2009 and 2008 (note 7). The Corporation's estimated maximum exposure to credit risk related to its investments in MAV Notes and US Auction Rate Securities is \$7.5 million.

(f) Liquidity risk:

If the Corporation does not earn sufficient 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 following table summarizes the time to maturity of the Corporation's financial liabilities as at December 31, 2010.

	<3 months	4-12 months	1-5 years	More than 5 years	Total
Accounts payable	\$ 144,378	\$ -	\$ -	\$ -	\$ 144,378
Long-term debt(1)	2,516	7,549	79,416	904,534	994,015
Interest on long-term debt(1)	14,528	43,362	223,179	14,013	295,082
	\$ 161,422	\$ 50,911	\$ 302,595	\$ 918,547	\$ 1,433,475

(1) Amounts represent the scheduled principal repayment of the senior secured credit facility and associated interest payments based on interest rates in effect on December 31, 2010.

The Corporation's policy on payment of accounts payable is net 30 days from receipt of invoice.

15. SUPPLEMENTARY INFORMATION:

(a) Supplemental cash flow disclosures:

	2010	2009
Changes in non-cash working capital items:		
(Increase) in accounts receivable and other	\$ (63,302)	\$ (19,853)
(Increase) in short-term investments	(167,406)	-
(Increase) decrease in inventories	(613)	2,226
Increase (decrease) in accounts payable	72,536	(1,749)
Net increase in non-cash working capital items	(158,785)	(19,376)
Changes in non-cash working capital relating to:		
Operations	\$ (50,143)	\$ 2,022
Investing	(108,642)	(21,398)
	\$ (158,785)	\$ (19,376)
	2010	2009
Cash and cash equivalents(1):		
Cash	\$ 18,857	\$ 107,074
Cash equivalents	1,205,589	855,944
	\$ 1,224,446	\$ 963,018

(1) Excludes \$167,406 of short term investments as at December 31, 2010.

(b) Per share amounts:

	2010	2009
Weighted average common shares outstanding	177,476,449	138,953,495
Dilutive effect of stock options and RSUs	5,778,675	4,557,334
Weighted average common shares outstanding – diluted	183,255,124	143,510,829

16. COMMITMENTS AND CONTINGENCIES:

(a) Commitments

The Corporation has the following commitments as at December 31, 2010.

Operating:

	2011	2012	2013	2014	2015	Thereafter
Office lease rentals	\$ 4,031	\$ 4,031	\$ 4,031	\$ 4,031	\$ 4,060	\$ 20,961
Diluent purchases	341,972	-	-	-	-	-
Other commitments	2,647	1,630	3,255	1,562	-	-
Annual commitments	\$ 348,650	\$ 5,661	\$ 7,286	\$ 5,593	\$ 4,060	\$ 20,961

Capital:

As part of normal operations, the Corporation has entered into a total of \$177.4 million in capital commitments to be made in periods through 2015.

(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.

17. CAPITAL DISCLOSURES:

The Corporation's objectives for managing capital include:

- managing capital investment risk and execution risk
- managing growth by financing projects on a phased basis

The Corporation uses a phased approach to development of its Christina Lake Project which is designed to reduce project capital investment and execution risk as well as provide ease of expansion.

The Corporation considers capital at December 31, 2010 to include long term debt of \$979.9 million (2009 – \$1,040.3 million) and share capital of \$3,821.6 million (2009 – \$3,137.7million).

The Corporation is in the growth stage of development. The combination of debt and equity used to fund the Corporation's ongoing activities will be guided by the amount of debt the project can service, restrictions the senior secured credit facilities place on incurrence of additional debt, and prevailing market conditions.



18. RELATED PARTY TRANSACTIONS:

In 2009, the Corporation entered into two Standby Purchase Agreements with WP X LuxCo S.à.r.l. ("WPX"), an affiliate of an owner of more than 20% of the Corporation's common shares which had the right to nominate three members of the Corporation's Board of Directors. Pursuant to the agreements, provided that certain conditions were met, the Corporation had the right to require WPX to purchase up to an aggregate of 13,246,398 of the Corporation's common shares at a price of \$24.00 per share for an aggregate purchase price of approximately \$317.9 million. In consideration for each standby commitment, the Corporation agreed to pay WPX a fee equal to 7.5% of the standby commitment upon exercise of the Corporation's rights. The \$24.00 price per share is considered to reflect the market value of the Corporation's shares at the time of the commitment. The Corporation exercised its rights under both Standby Purchase Agreements, and thereby received gross proceeds of \$317.9 million and paid WPX fees totaling \$23.8 million, equal to 7.5% of the commitments.

In 2009, the Corporation entered into two Standby Purchase Agreements with CNOOC Belgium BVBA ("CNOOC"), which is a shareholder of the Corporation and which had nominated a member of the Corporation's Board of Directors. Pursuant to the agreements, provided that certain conditions were met, the Corporation had the right to require CNOOC to purchase up to an aggregate of 11,461,933 of the Corporation's common shares at a price of \$24.00 per share for an aggregate purchase price of approximately \$275.1 million. In consideration for each standby commitment, the Corporation agreed to pay CNOOC a fee equal to 7.5% of the standby commitment. The \$24.00 price per share is considered to reflect the market value of the Corporation's shares at the time of the commitment. The Corporation exercised its rights under both Standby Purchase Agreements and thereby received gross proceeds of \$275.1 million and paid CNOOC fees totaling \$20.6 million, equal to 7.5% of the commitments.

19. COMPARATIVE FIGURES:

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



CORPORATE INFORMATION

BOARD OF DIRECTORS:

A. Boyd Anderson (Lead Director)
Former Director
Amoco Canada Petroleum Co. Ltd.
Calgary, Alberta

Harvey Doerr
Former Executive VP
Murphy Oil Corporation
Invermere, British Columbia

Robert B. Hodgins
Independent Businessman
Calgary, Alberta

Peter R. Kagan
Managing Director
Warburg Pincus
New York, New York

David B. Krieger
Managing Director
Warburg Pincus
New York, New York

Honourable E. Peter Lougheed
Counsel, Bennett Jones LLP
Calgary, Alberta

William J. McCaffrey
Chairman, President and CEO
MEG Energy Corp.
Calgary, Alberta

James D. McFarland
President and CEO, Valeura Energy Inc.
Calgary, Alberta

David J. Wizinsky
Corporate Secretary, MEG Energy Corp.
Victoria, British Columbia

Li Zheng
President, CNOOC Canada Limited
Calgary, Alberta

EXECUTIVE OFFICERS:

William J. McCaffrey, P.Eng.
Chairman, President and CEO

Dale Hohm, CA
Chief Financial Officer

Grant Boyd, P.Eng.
VP Growth and Emissions Management

Jamey Fitzgibbon, P.Eng.
VP Special Projects

Jim Kearns
VP Supply and Marketing

John Rogers, CA
VP Investor Relations

Ted Semadeni, LL.B.
General Counsel

Richard Sendall, P.Eng.
VP Business and Strategic Planning

Chris Sloof, P.Eng.
VP Projects

Don Sutherland
VP Regulatory and Community Relations

Bryan Weir, P.Eng.
VP Operations

Suzanne Wilson
Director of Human Resources and
Corporate Communications

David J. Wizinsky, LL.B.
Corporate Secretary

Chi-Tak Yee, P.Eng.
VP Reservoir and Production

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Chartered Accountants
Calgary, Alberta

INDEPENDENT QUALIFIED RESERVE EVALUATORS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Bennett Jones LLP
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT

Olympia Trust Company
Calgary, Alberta and Toronto, Ontario

ABBREVIATIONS:

bbl	barrel
bbls	barrels
bbls/d	barrels per day
MMbbls	million barrels
mcf	thousand cubic feet
MW	megawatts
MWh	megawatt hours



