MEG ENERGY

MEG ENERGY CORP.

Annual Report 2011

A Pure Play
Oil Sands Investment

MEG Energy Corp. is a Canadian oil sands company focused on sustainable in situ development and production in the southern Athabasca oil sands region of Alberta. MEG has acquired a large, high quality resource base – one that we believe holds some of the best in situ resources in Alberta. With these resources and a well-formulated strategic growth plan, MEG is positioned to be a strong oil sands player for many years to come.

MEG ENERGY ANNUAL REPORT 2011

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Operational and Financial Overview

2011 was a significant year for MEG Energy. It represented the first year in which we were able to demonstrate full commercial production at our Christina Lake Project. Performance from an operational and financial perspective began strong early in the year, with that momentum building to year-end. Some of the key performance highlights include:

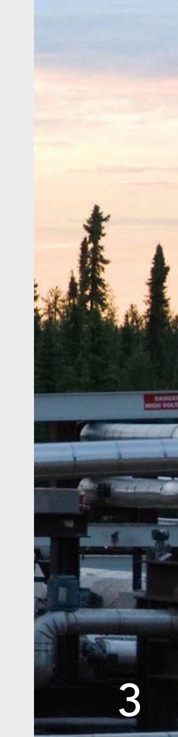
- Bitumen production for 2011 averaged 26,605 barrels per day (bpd) – an approximately 25% increase from 21,257 bpd year-over-year. Average production for the year exceeded nameplate design capacity of 25,000 bpd with the inclusion of a planned plant turnaround throughout the month of September.
- A decrease in steam-oil ratio (SOR) from 2.5 in 2010 to 2.4 in 2011, reflecting highly efficient operations.
- Operating costs decreased approximately 22% year-over-year from $19.89 per barrel in 2010 to $15.46 in 2011. With the inclusion of power sales generated through MEG's cogeneration facilities, net operating costs decreased approximately 47% year-over-year from $16.13 per barrel in 2010 to $10.96 in 2011.
- Cash operating netback increased approximately 39% from $30.92 per barrel in 2010 to $43.15 per barrel in 2011.

2011 QUARTERLY PERFORMANCE / FULL YEAR

($ per barrel unless specified)	Q1	Q2	Q3	Q4	2011	2010
Bitumen production – barrels per day	27,653	27,826	20,945	30,032	26,605	21,257
Steam-oil ratio	2.5	2.5	2.5	2.3	2.4	2.5
West Texas Intermediate (WTI) US$ / barrel	94.10	102.56	89.76	94.06	95.12	79.53
Differential – WTI / blend %	29.0%	22.9%	25.2%	19.1%	23.5%	23.0%
Bitumen realization	49.57	62.78	51.79	67.99	58.74	50.79
Transportation	(1.42)	(1.18)	(1.93)	(1.19)	(1.39)	(1.61)
Royalties	(2.64)	(3.69)	(2.82)	(3.66)	(3.24)	(2.13)
Net bitumen revenue	45.51	57.91	47.04	63.14	54.11	47.05
Energy costs	5.54	5.39	5.05	4.61	5.14	6.47
Non-energy costs	8.68	8.74	17.20	8.55	10.32	13.42
Power sales	(5.59)	(2.77)	(5.13)	(4.66)	(4.50)	(3.76)
Net operating costs	8.63	11.36	17.12	8.50	10.96	16.13
Cash operating netback [1]	36.88	46.55	29.92	54.64	43.15	30.92
Net income - $millions	45.4	42.5	(115.2)	91.1	63.8	49.6
Per share, diluted	0.23	0.21	(0.60)	0.46	0.32	0.27
Operating earnings - $millions [2]	20.9	36.4	5.4	57.8	109.3	2.5
Per share, diluted	0.11	0.18	0.03	0.29	0.55	0.01
Cash flow from operations - $millions [2]	69.3	88.1	26.1	121.6	304.6	124.5
Per share, diluted	0.35	0.44	0.13	0.61	1.54	0.68
Cash and short-term investments - $millions	2,034.5	1,926.4	1,831.9	1,647.1	1,647.1	1,391.9
Long-term debt - $millions	1,673.2	1,660.4	1,791.7	1,751.5	1,751.5	968.1
Capital cash investment - $millions	210.5	209.6	243.2	268.8	928.9	483.4

(1) Cash operating netbacks are calculated by deducting the related royalties and diluent, transportation, operating costs and realized gains/losses on financial derivatives from bitumen sales revenues, on a per barrel basis. Please refer to note 3 of the Operating Summary table within the "Results of Operations" section in the attached Management's Discussion and Analysis ("MD&A").

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



Message to Shareholders

For MEG Energy, 2011 was another exciting chapter in a growing Canadian energy success story. The measure of our success can be viewed in many ways but, most clearly, 2011 was the first full year that we had the opportunity to demonstrate production at commercial rates. Coming into the year, our Christina Lake Phase 2 Project was running at full capacity, having achieved the most rapid ramp-up yet seen in the in situ oil sands industry. Not only did we achieve record ramp-up to capacity, but we continued to build on that performance throughout 2011. By the end of the year, we were running steadily at production rates substantially above design capacity, an indication of both engineering and operating expertise of the MEG team, and our high quality resource base.

Building On An Exceptional Resource Base

MEG's resource base, which is the foundation on which we are building our long-term strategy, comprises approximately 2 billion barrels of independently evaluated proved plus probable reserves and nearly 4 billion additional barrels of best-estimate contingent resources. Covering more than 900 square miles, MEG's leases are all located in the southern Athabasca oil sands region. This geographical concentration of assets is very much aligned with MEG's highly focused business strategy – we know the area geology well, we have strong relationships with regional stakeholders and we can leverage proprietary infrastructure. This focus gives us confidence that the performance of future phases will remain consistent with the results we've achieved so far.

Our current producing assets are in the Christina Lake area where we are building off a successful 2011. We have established production targets of 26,000 to 28,000 barrels per day in 2012, with plans to exit the year at 30,000 barrels per day – about 8% higher than our 2011 average rate. In 2013, we expect to more than double our production capacity to 60,000 barrels per day with the commissioning and start-up of Phase 2B. Production is expected to ramp-up over the balance of the year and into 2014. Our history demonstrates MEG's ability to construct and operate top-tier projects and that's a record that Phase 2B is well on track to maintain.

As we continued to execute our long-term growth strategy, we reached two more important milestones in early 2012. Christina Lake Phase 3, a multi-stage project with a design capacity of 150,000 barrels per day, was granted the second of two key regulatory approvals in early February. And, shortly on the heels of that approval, we began formal consultations launching the regulatory application process for Surmont, a multi-stage 120,000 barrel per day project just north of our current operations.

Together, the remaining phases of the Christina Lake Project and the first phase of Surmont are planned to bring MEG's total design production capacity to 260,000 barrels per day in 2020, a tenfold increase over current capacity.

Looking beyond 2020, we expect further development of the Surmont Project to take us to production capacity of 330,000 barrels per day. At the same time, we will continue to define our resource base in MEG's Growth Properties, west of Christina Lake. Together, these projects represent significant and sustained growth potential so, while many energy companies globally are struggling to grow or even maintain current production, we have a substantial project inventory.

Construction on Phase 2B of the Christina Lake Project is well underway, with commissioning and start-up scheduled for 2013.

Building On The Experience Of An Exceptional Team

While our large resource base and portfolio of new projects may represent the most exciting aspect of our growth strategy for industry-watchers, for MEG growth is not just about adding new phases. We also place significant focus on unlocking new value from our existing operations. We see MEG as a "learning organization" and, from the production of our first barrel in 2008, we have constantly challenged ourselves to innovate and improve. This approach can be seen most clearly in our success in exceeding design production capacity at Christina Lake, producing more than 30,000 barrels per day – or 20% above design capacity – in the fourth quarter of 2011. This is a rare accomplishment in the oil sands industry and one of which we are very proud.

Leveraging new production from our base operations represents the lowest capital cost, highest return new barrels in our portfolio, bringing production and corresponding cash flow to the bottom line relatively quickly. In addition, our fixed costs are spread over more barrels with every incremental increase in production, helping to make our net operating costs per barrel among the lowest in the industry.

It's a quiet, but very effective way to add value, and across nearly every measure from cost and energy-efficiency to recovery rates, the returns are remarkable – and we're just getting started. Building on this strategy, in 2012, we have begun to see results from several new efficiency initiatives in our base operations.

These initiatives include infill wells which, guided by high-tech directional drilling, can place a horizontal collector well in the sweet-spot between existing wells, increasing recovery and lowering our steam-oil ratio (SOR). Projects underway also include the injection of trace amounts of natural gas into mature wells to replace a portion of the steam energy component and maintain pressure in the reservoir. This, again, substantially improves energy efficiency, lowering SORs and related energy costs.

These two base operation efficiency initiatives (and others) help to create a "virtuous circle" with reduced SORs freeing up steam generation capacity which can then be directed into new well pairs, further bolstering our baseline production from existing assets. Although we are still relatively early in applying these technologies, we are already seeing encouraging results and, as always, we will look forward to applying what we've learned to future developments.

Building Value Into Every Barrel We Produce

While our approach to successfully establishing our resource base and plans to grow our production have garnered more attention over the past year, we have also been working diligently on plans to build more value into every barrel we produce.

This strategy began with our early investment in the Access Pipeline. The advantage of Access, running between Christina Lake and Edmonton, is that it essentially places our wellhead at a major refining and transportation hub – supporting what we call a "hub and spoke" strategy. From Edmonton, pipeline connections are available to traditional markets in Eastern Canada and the U.S. mid-continent, providing a range of market options for our barrels. Future connections are also available to developing markets with the extension of new pipeline capacity to the U.S. Gulf Coast and new or expanded pipeline capacity to Canada's West Coast.

Concurrent with the development of these new markets, MEG is constructing a 900,000 barrel storage facility called the Stonefell Terminal, connected to the Access pipeline. When this "hub" is completed in 2013 and with the further development of market "spokes" over the coming years, we expect to have significant options to make large batch-shipments to a variety of markets. This active strategy should further improve MEG's ability to dampen the impacts of sometimes volatile North American market prices and differentials that have buffeted the broader industry.

Upholding Values

These are just a few examples of our efforts to add value for our shareholders. But beyond just "value," we also know that it's important to reflect the "values" of our all our stakeholders in how we support economic growth and opportunity while managing environmental impacts. Happily, these elements are closely related because well-run, highly efficient operations tend to be those that are most financially successful and most environmentally responsible at the same time. This is our common focus.

For example, our efforts to improve energy efficiency through cogeneration of steam and electricity and on-site technology to reduce SORs result not only in lower costs, but also in lower air emissions. Our per barrel carbon intensity is among the lowest in the oil sands industry, and lower than the average of barrels imported into the North American energy market.

We strive for similar efficiencies in how we manage water use and land disturbance and reclamation, and we've realized similar success. "Doing more with less" may be an old and somewhat tired phrase, but it is nonetheless an effective approach to managing a successful, values-based business.

Access Pipeline provides connectivity to a number of key traditional and developing markets.

A Promising Future

Every member of the MEG team is a steward of our values and everyone has a role to play in building this exciting story. And, as we've grown, we have put together a team that represents some of the best the business has to offer, from industry veterans who bring vast experience, to young up-and-comers who bring new thinking and tremendous energy. By maintaining a strong, learning culture, and valuing both individual contribution and the power of teamwork, we are continuing our drive to be an innovator and employer of choice.

Together, we have built a proven track record and promising future based on our high quality resource base, disciplined capital investment and well-run, cost-efficient operations. On behalf of our employees and your Board of Directors, I thank you for your past support and I look forward to an exciting future.

Sincerely,

W. J. McCaffrey

Bill McCaffrey
President & CEO

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

"Together, we have built a proven track record and a promising future."

Proven Performance

2011: Our Goals and Results

GOAL #1

Achieve average annual production of 25,000 to 27,000 barrels per day at non-energy operating costs of $9 to $11 per barrel.
Production in 2011 averaged 26,605 barrels per day, at the high end of our target range and exceeding design production capacity of 25,000 barrels per day. Non-energy operating costs averaged $10.32 for the full year.

GOAL #2

Maximize productivity and reliability of existing plants.
Our Christina Lake plant performed consistently above design production capacity, finishing the year with fourth quarter production exceeding design capacity by more than 20% at an average 30,032 barrels per day. A complete turnaround of the plant was successfully completed in September of 2011, supporting ongoing reliability. During the turnaround, debottlenecking work was carried out on MEG's Phase 2 high pressure steam separator, providing additional steam capacity to support higher baseline production going forward. Outside of the turnaround month of September, plant availability stood at 98.5%.

GOAL #3

Continue with Phase 2B development, targeting over 90% completion of engineering and delivery of long-lead time equipment by the end of the year.
At year-end, detailed engineering was 93% complete with all major vessels ordered and remaining deliveries underway in the early part of 2012. Approximately 60% of the total $1.4 billion project budget was locked in by year-end.

GOAL #4

Obtain ERCB approval for Christina Lake Phase 3.
Regulatory approval for Phase 3 was granted in early 2012, well in advance of MEG's critical path for engineering, procurement and construction of the planned project, which has a design capacity of 150,000 barrels per day.

GOAL #5

Further delineate leases in the Growth Properties.
Fifty core holes were drilled in MEG's Growth Properties in 2011 and by year-end a total of approximately 230 square kilometres (89 square miles) of three-dimension seismic data had been accumulated on these leases, advancing resource definition for future development. Additional core hole drilling and seismic work was also carried out on our Christina Lake leases to delineate resources for nearer-term development and on our Surmont leases in preparation for regulatory applications.

A Promising Future

2012: Our Goals and Plans to Reach Them

GOAL #1

Achieve average annual production of 26,000 to 28,000 barrels per day at a non-energy operating cost average of $10 to $12 per barrel.
We have increased our production guidance in 2012 to reflect ongoing efficiency measures and production enhancements at our Christina Lake plant.

GOAL #2

Maximize productivity and reliability of existing plants.
In September, a three-week shutdown of our Christina Lake plant is planned to tie-in facilities for Phase 2B and support ongoing plant reliability. Initiatives to enhance production from existing operations, including infill wells, injection of non-condensable gas into producing reservoirs, and additional steam generation and new well pairs are planned for implementation and evaluation through the course of the year.

GOAL #3

Advance Phase 2B toward target completion in 2013 and advance development strategy and engineering work for Phase 3.
Construction of Phase 2B is expected to be significantly advanced over the course of 2012. Approximately $60 million in engineering and design work is planned to determine optimum timing and sizing of the initial stage of the Phase 3 project.

GOAL #4

Submit regulatory application for development of the Surmont Project.
Formal consultation with stakeholders is slated to begin in the first quarter of 2012, with a regulatory application for a 120,000 barrel per day project targeted for the second half of the year

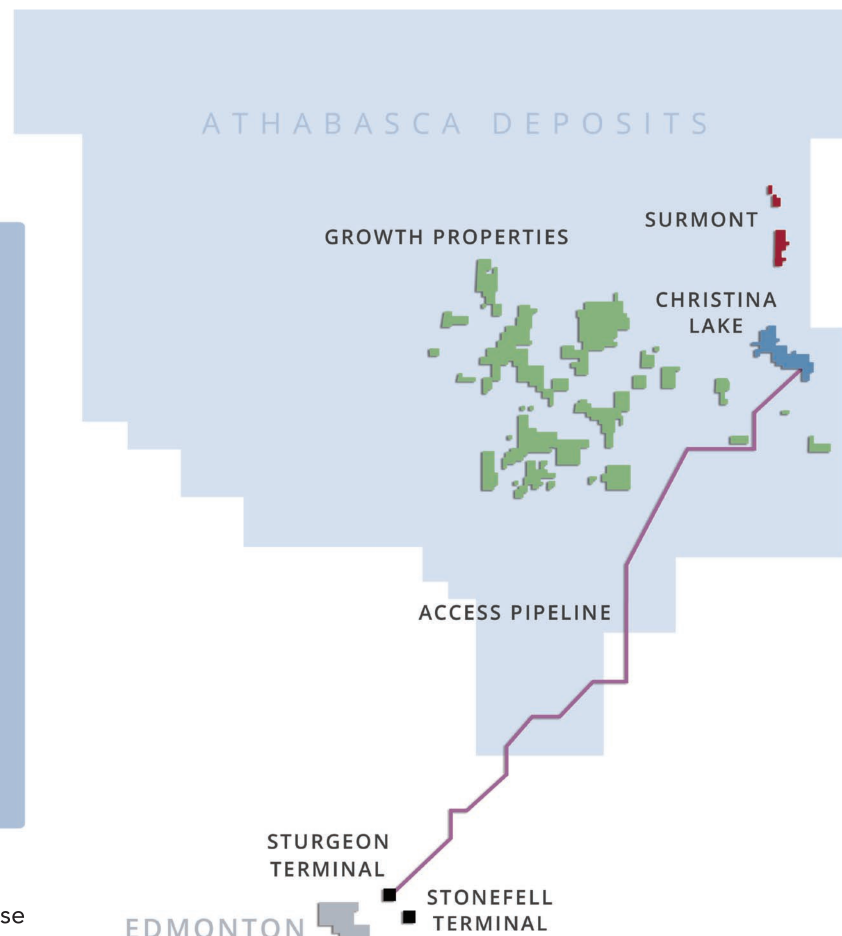
GOAL #5

Advance MEG's hub-and-spoke market access strategy.
Two new pumping stations are planned for completion on the jointly-owned Access Pipeline, providing additional takeaway capacity from our producing assets to the Edmonton refining and transportation hub. In addition, we are targeting regulatory approval in late 2012 or early 2013 for a planned expansion of Access to accommodate future production growth. Work is also expected to continue through the year on the 900,000 barrel Stonefell Terminal near the southern terminus of Access.

Exceptional Resource Base*

MEG Energy's oil sands leases are located in the southern Athabasca oil sands region of Alberta, an actively producing region with a high quality resource base. MEG's leases cover more than 2,300 square kilometres over three key asset areas:

- **Christina Lake**
- **Surmont**
- **Growth Properties**



Beneath the surface of these leases are an estimated 2.1 billion barrels of proved plus probable reserves and an additional 3.8 billion barrels of best-estimate contingent resources. This large resource base is the foundation of our current production and future growth plans.

The concentration of MEG's leases in the southern Athabasca allows us to leverage our geological expertise in the region as we expand our operations. Christina Lake – home to MEG's current 25,000 barrel per day facilities and next two phases of growth – is familiar territory. The geological trend found at Christina Lake also underlies Surmont, further north. We know the play – and how to play it.

OIL SANDS ASSETS AT A GLANCE

	CHRISTINA LAKE	SURMONT	GROWTH PROPERTIES
	Phase 1 and 2 currently producing; 2012 Production Guidance 26,000 – 28,000 bpd; Regulatory approvals in place for 210,000 bpd	Commenced regulatory process for 120,000 bpd, multi-phased project	Resource delineation in progress as part of long-term growth strategy
2P Reserves	2,060 MMbbls	—	—
Contingent Resources (best estimate)	988 MMbbls	863 MMbbls	1,967 MMbbls
2P Reserves PV-10%	$13,502 MM	—	—
Resources PV-10%	$2,780 MM	$3,815 MM	$7,194 MM
Lease Holding (Evaluated)	51,200 acres	20,480 acres	192,000 acres
Lease Holdings (Unevaluated)	—	—	334,080 acres

Even before MEG produced its first barrel of oil in 2008, we planned for growth by converting contingent resources to better-defined "reserves". As MEG prepares to expand its operations, an ongoing program of seismic exploration and core-hole drilling provides a clearer, long-term view of how to best develop our leases, helping to remove risk from growth plans.

At current production rates, MEG's proven reserve life is in excess of 60 years, but we're not sitting still. Over time, we expect to further increase our reserve base while expanding production capacity tenfold, as we target 260,000 barrels per day by 2020.

Year-end independent reserves evaluation reported a 17% year-over-year increase in proved reserves to 708 million barrels and a 7% increase in proved plus probable reserves to more than 2 billion barrels.

** Lease holdings are those held by MEG as of December 31, 2011. Estimates of MEG's reserves and contingent resources and net present values are based upon a report prepared by GLJ Petroleum Consultants Ltd., effective December 31, 2011. There is no certainty that it will be commercially viable to produce any of the contingent resources and the net present values shown do not necessarily represent fair market value. Statements relating to reserves and contingent resources estimates and certain other statements in this annual report relating to MEG's development plans, 2012 goals and expectations constitute forward-looking information. For further information and important advisories regarding forward-looking information and MEG's reserves and resources please refer to MEG's annual information form dated March 28, 2012.*

Exceptional Execution

Christina Lake Project

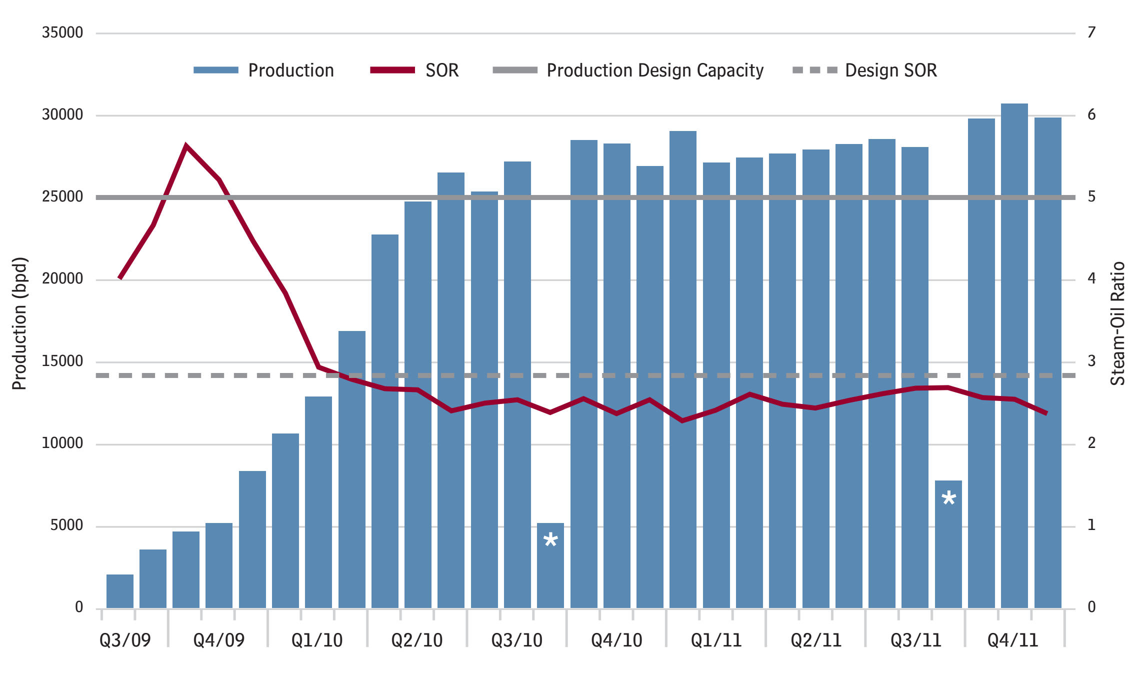
MEG's current oil sands development is focused on the multi-stage Christina Lake Regional Project covering approximately 200 square kilometres of oil sands leases containing more than 2 billion barrels of proved plus probable reserves.

MEG is recovering these reserves using steam-assisted gravity drainage (SAGD) technology. While SAGD technology is well-proven and widely used in the oil sands industry, MEG has demonstrated industry-leading performance in several aspects of our operations.

Those operations began in 2008 with the start-up of Phase 1 at a production capacity of 3,000 bpd. This was quickly followed with Phase 2 in 2009, which increased total design production capacity to 25,000 bpd. Following start-up, full production volume for the combined Phases 1 and 2 was reached in just 10 months, a record-setting pace for the in situ oil sands industry.

Building on that accomplishment, the MEG team focused on reducing our steam-oil ratio, providing increased production volume from our existing assets. Those efforts drove 2011 average production volumes of 26,605 bpd, with fourth quarter production rates of 30,032 bpd – 20% above the original facility design capacity. The corresponding steam-oil ratio for 2011 averaged 2.4, among the best in the industry.

With similar geology underlying our next stages of growth and the same core team of engineering, geological and operating expertise, we're confident that we will continue our track record of exceptional execution.



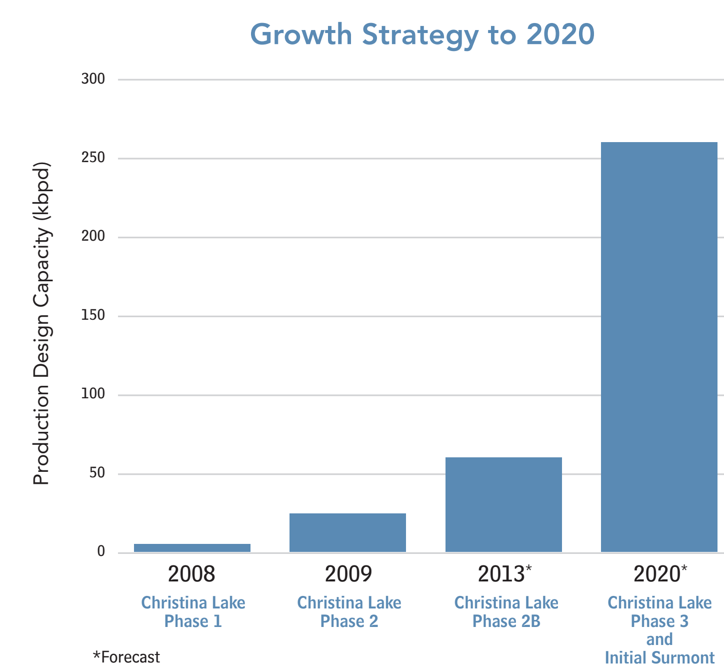
MEG's growth plan targets production capacity of 260,000 barrels per day by 2020, a tenfold increase over current capacity.

Growth Plan: The View to 2020

Phase 2B is the next step in Christina Lake's development, with a planned 35,000 bpd in additional production capacity, Phase 2B is expected to more than double our production volumes when it is fully ramped up. The project is on budget and on schedule to begin steaming and initial production in 2013.

Following 2B, the next key piece of the Christina Lake Project is Phase 3, a multi-stage project targeting an additional 150,000 bpd of production capacity. The project was approved by regulators in early 2012 with its first stage scheduled for start-up in 2016.

When fully developed over all three phases, the Christina Lake Regional Project will have a design production capacity of 210,000 bpd.



Surmont Project

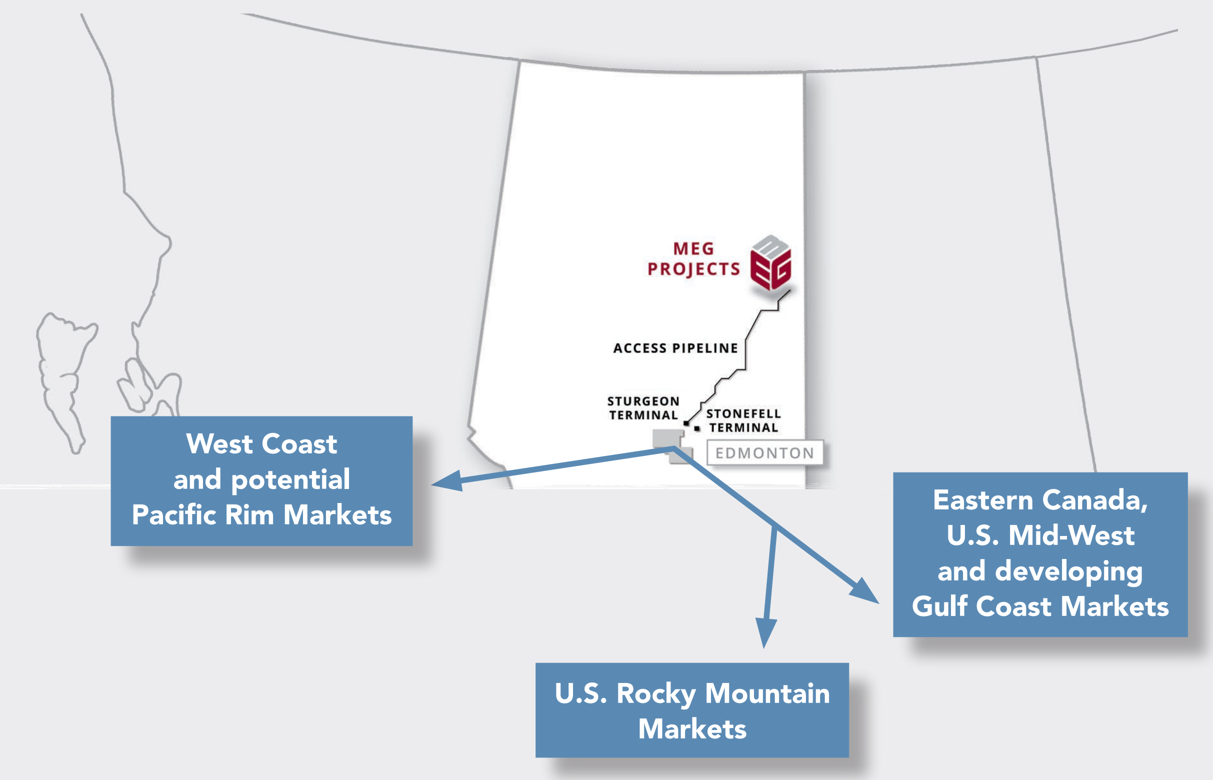
Following on our plans for Christina Lake, in early 2012 MEG launched the regulatory process for the next phase of our long-term growth strategy, the Surmont Project. Surmont, located north of our current operations is a proposed multi-stage SAGD development with a total design production capacity of approximately 120,000 bpd.

The Surmont Project will feature SAGD bitumen recovery from the McMurray Formation, a reservoir with properties very similar to those at Christina Lake. The initial stage of Surmont is anticipated to play a significant role in MEG's overall growth strategy of achieving 260,000 bpd in production capacity by 2020.

Connecting to Markets

MEG is building on a long-term strategy to add value to our products by connecting our oil sands energy supply to market demand. The strategy starts with our 50% ownership in the Access Pipeline, which connects our production assets to the large refining and transportation hub near Edmonton, Alberta. From the Edmonton hub, we are able to connect to traditional domestic and U.S. mid-continent markets. And, as new pipeline proposals are more fully developed in the years ahead, we are well-positioned to access emerging markets on the U.S. Gulf of Mexico and the Pacific Rim.

USING A "HUB AND SPOKE STRATEGY" TO ACCESS MULTIPLE MARKETS



Building on this flexible "hub and spoke" strategy, MEG is constructing a new terminal and tank facility called Stonefell located near the Access terminal near Edmonton. With a planned 900,000 barrel capacity of tankage targeted for completion in 2013, Stonefell is expected to add significant value by:

- Allowing MEG to blend large product batches to improve the quality and price realization of our production
- Mitigating the impacts of periodic pipeline restrictions, which can temporarily distort market prices
- Providing the opportunity to acquire and store diluent for blending into our products when market conditions are favourable

Together, the flexibility and connections to multiple markets provided by Access and Stonefell improve our ability to optimize the value of every barrel MEG produces.

As production grows, there are options to increase the capacity and reach of the Access line. In 2012, two new pumping stations are expected to be completed and engineering and regulatory work is planned to "loop" the existing line, bringing on additional pipeline capacity to accommodate planned production growth.

Innovating for the Future

MEG continually examines new technologies that target increased resource recovery, lower costs and reduced environmental impacts. As we move forward, technology and innovation will play a key role in unlocking incremental economic potential of our assets and ultimately maximizing value for our shareholders.

Cogeneration

Cogeneration is the process of simultaneously producing steam and electricity. In MEG's operations, the steam is used for SAGD bitumen recovery, while the electricity is used at the plant site, with excess power sold to Alberta's power grid.

Advantages of cogeneration over conventional steam boilers include:

- The "energy return on investment" – the amount of useable energy created from the burning of natural gas – is increased, as both bitumen and electricity are produced.
- Electricity produced at the plant site helps ensure steady and reliable power, reducing the risk of a plant shutdown due to power grid interruptions.
- The sale of excess electricity helps offset production costs. In 2011 power sales had the effect of recovering 88% of energy-based operating costs.
- The electricity provided to the power grid has a carbon footprint less than half the provincial average, helping to reduce total greenhouse gas emissions. In 2011, electricity from MEG's cogeneration facilities had the effect of reducing greenhouse gas emissions by 412,000 tonnes compared to what emissions would have been based on the Alberta provincial grid average. That's the equivalent of taking 80,000 cars off the road.

Non-Condensable Gas Co-Injection

The steam injected into the oil sands reservoir in the SAGD process helps bitumen flow in two ways – reducing its viscosity by heating it, and increasing the pressure in the reservoir to help the bitumen flow.

As the steam condenses back to a liquid state when it cools, the pressure declines. Co-injecting trace amounts of a non-condensable gas, like methane, replaces a portion of the steam energy component and maintains pressure in the reservoir. The injected gas is recovered with the bitumen and cycled back into the process.

MEG is field-testing this technology with a pilot project in 2012 and early results are encouraging. If it performs as expected, we should be able to reduce the amount of steam required for every barrel we produce, allowing us to reduce per-barrel costs and greenhouse gas emissions.

MEG places a significant focus on unlocking new value from our existing operations through proven and emerging technology.

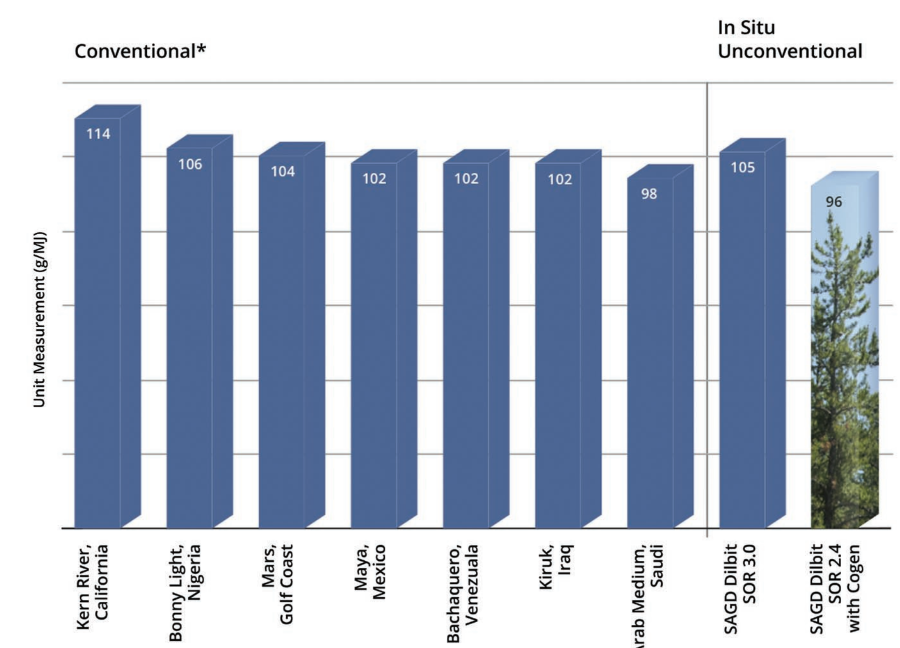
Infill Wells

Using "infill wells" guided by high-tech directional drilling, we can place a horizontal collector well in the sweet-spot between existing wells. This technique allows us to not only increase the volume of bitumen recoverable in the reservoir, it also improves our energy efficiency and related costs and emissions as no new steam is required.

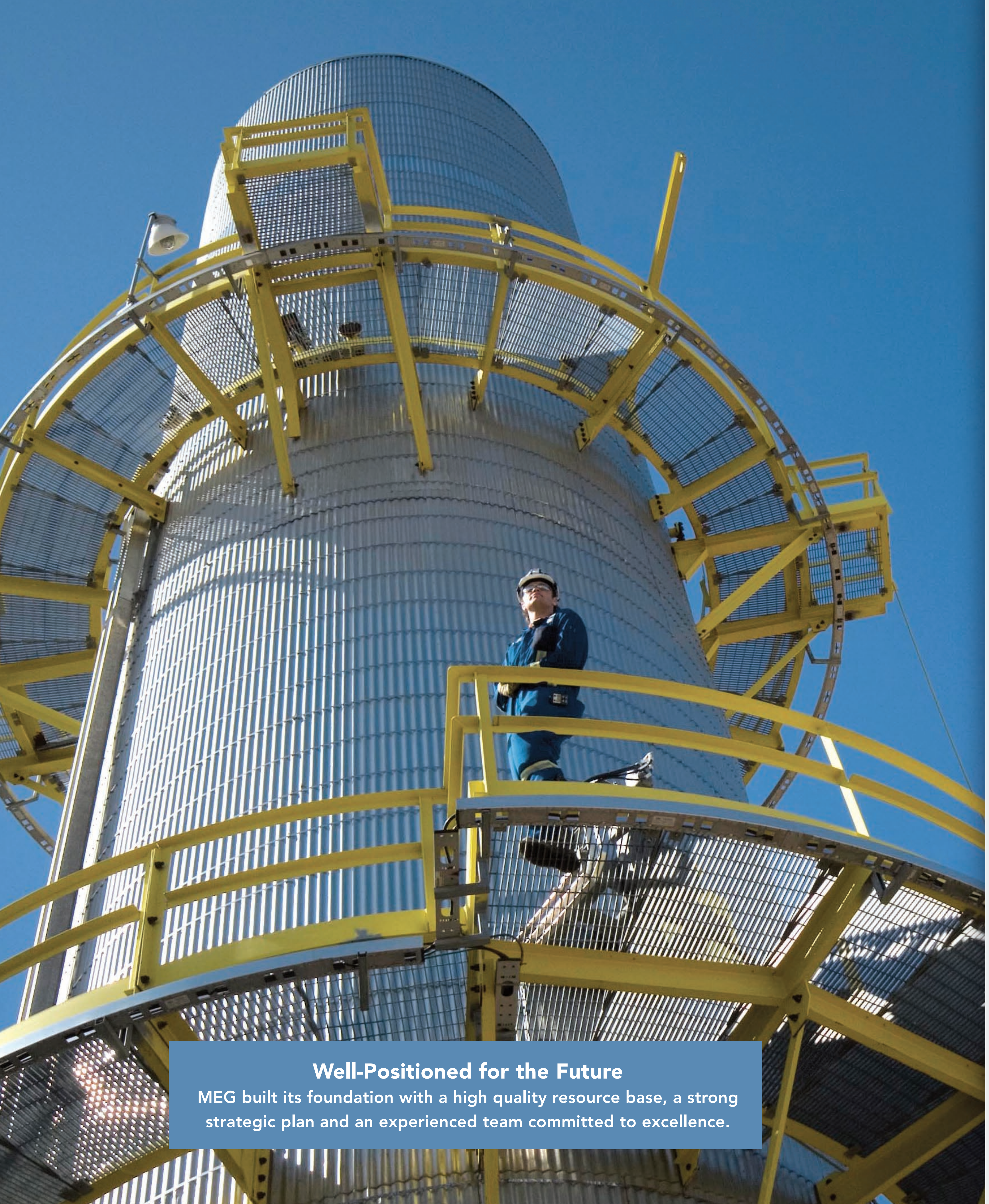
Efficiency Drives Reduced Environmental Impacts

With the benefits of cogeneration facilities, a high quality reservoir and ongoing efforts to drive energy efficiency, MEG produces one of the lowest greenhouse gas intensity barrels in the oil sands industry.

MEG's production has a smaller carbon footprint than many conventional sources of oil.



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



Well-Positioned for the Future
MEG built its foundation with a high quality resource base, a strong strategic plan and an experienced team committed to excellence.

Management's Discussion and Analysis

Financial Statements

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the year ended December 31, 2011 is dated February 23, 2012. Effective January 1, 2011, the Corporation adopted International Financial Reporting Standards ("IFRS"). This MD&A should be read in conjunction with the Corporation's audited financial statements and notes thereto for the year ended December 31, 2011. In 2010, the CICA Handbook was revised to incorporate IFRS, and to require publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. In this MD&A, the term "Canadian GAAP" refers to Canadian GAAP before the adoption of IFRS. 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 projects on MEG's additional leases (the "Growth Properties"); and the anticipated sources of funding for operations and capital investments. Such forward-looking information is based on management's expectations and assumptions regarding future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), plans for and results of drilling activity, environmental matters, business prospects and opportunities. By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: risks associated with the oil and gas industry (e.g. operational risks and delays in the development, exploration or production associated with MEG's projects; the securing of adequate supplies and access to markets and transportation infrastructure; the 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 and the annual information form to be filed in March of 2012 (the most recent of which is the "AIF") along with MEG's other public disclosure documents. A copy 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.

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.

NON-IFRS FINANCIAL MEASURES

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

OVERVIEW

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

MEG owns a 100% working interest in over 900 sections of oil sands leases. In a report (the "GLJ Report") dated as at December 31, 2011, GLJ Petroleum Consultants Ltd. (''GLJ"), estimated that the MEG oil sands leases it had evaluated contained 2.1 billion barrels of proved plus probable bitumen reserves and 3.8 billion barrels of contingent bitumen resources (best estimate). The Corporation has identified two commercial SAGD projects, the Christina Lake project and the Surmont project. MEG believes, as supported by GLJ estimates, that the Christina Lake project can support over 200,000 barrels per day ("bbls/d") of sustained production for 30 years and that the Surmont project can support 100,000 bbls/d of sustained production for over 20 years. In addition, the Corporation holds other leases at the Growth Properties that are in the resource definition stage and that could provide significant additional development opportunities.

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MEG is currently focused on the phased development of the Christina Lake project. MEG's first two production phases at the Christina Lake project, Phases 1 and 2, commenced production in 2008 and 2009, respectively, and have a combined design production capacity of 25,000 bbls/d. Phase 2B, a 35,000 bbls/d expansion, has received regulatory approvals. Site construction has commenced and is anticipated to be complete in 2013. MEG's combined design production capacity at the Christina Lake project is anticipated to reach 60,000 bbls/d once Phase 2B is complete. Phase 3 contemplates a multi-phased development, totalling an additional 150,000 bbls/d, that when completed would bring MEG's total design production capacity at the Christina Lake project to 210,000 bbls/d. MEG has received regulatory authorization to proceed with Phase 3, following approvals issued February 13, 2012 by Alberta Environment and Water and the previous approval on January 31, 2012 by Alberta's Energy Resources Conservation Board. In addition, MEG is currently preparing a regulatory application for a multi-phase development at Surmont and expects to file a regulatory application in 2012.

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

SUMMARY ANNUAL INFORMATION

($000, except per share amounts)	2011	2010	2009[(1)]
Total revenue, net of royalties	1,033,226	730,286	23,422
Net income	63,837	49,558	51,176
Per share – basic	0.33	0.28	0.37
Per share – diluted	0.32	0.27	0.36
Total assets	6,201,049	5,043,265	4,269,493
Total non-current liabilities	2,216,945	1,189,141	1,173,380

(1) Amounts for periods prior to the Corporation's adoption of IFRS on January 1, 2010 are presented in accordance with Canadian GAAP.

Net operating costs from oil sands operations were capitalized prior to December 31, 2009. Effective December 1, 2009, planned principal operations of the Corporation's Christina Lake project commenced and the recognition of bitumen blend and power sales began. Prior to this date, revenues consisted primarily of interest income. The success of the production ramp-up has enabled the Corporation to performance-test the integrated Phase 1 and 2 facilities and consistently exceed the original plant design production capacity of 25,000 bbls/d since mid-2010.

Net income was positively influenced by the increase in cash operating netback (2011 - $418.7 million; 2010 - $240.3 million; 2009 - $1.9 million loss) due to the increase in bitumen production and pricing from 2009 through 2011. Net income was also impacted by foreign exchange gains and losses (2011 - $35.7 million loss; 2010 - $49.1 million gain; 2009 - $120.1 million gain) attributable to fluctuations in the rate of exchange between the Canadian and U.S. dollar in translating the Corporation's U.S. dollar-denominated debt, the increase in depletion and depreciation (2011 - $124.3 million; 2010 - $97.9 million; 2009 - $3.1 million), and modification of long-term debt (2011 - $2.8 million gain; 2010 – nil; 2009 – $21.3 million loss).

Total assets have increased 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.

Investment activity was partially funded by an $890.0 million, net of issue costs, private placement share issue in 2009 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. On March 18, 2011, the Corporation refinanced its existing senior secured term loans and revolving credit facilities. Under the terms of the agreement, the Corporation increased its borrowings under the senior secured credit facilities from US$999.4 million to US$1.0 billion. In addition to the amendments to the existing borrowing facilities, on March 18, 2011 the Corporation issued US$750.0 million in aggregate principal amount of 6.5% senior unsecured notes. For a detailed discussion of the debt amendment, see "LIQUIDITY AND CAPITAL RESOURCES – Cash Flows – Investing Activities".

OPERATIONAL AND FINANCIAL HIGHLIGHTS

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

	Year ended December 31	
($/bbl unless specified)	2011	2010
Bitumen production – bbls/d	26,605	21,257
Steam to oil ratio	2.4	2.5
West Texas Intermediate (WTI) US$/bbl	95.12	79.53
Differential – WTI/Blend %	23.5%	23.0%
Bitumen realization	58.74	50.79
Operating costs:		
Energy	5.14	6.47
Non-energy	10.32	13.42
Operating costs	15.46	19.89
Power sales	(4.50)	(3.76)
Net operating costs	10.96	16.13
Cash operating netback(1)	43.15	30.92
Net income - $000	63,837	49,558
Per share, diluted	0.32	0.27
Operating earnings - $000(2)	109,255	2,471
Per share, diluted(2)	0.55	0.01
Cash flow from operations - $000(2)	304,627	124,525
Per share, diluted(2)	1.54	0.68
Cash and short-term investments - $000	1,647,069	1,391,852
Long-term debt - $000	1,751,539	968,064
Capital cash investment - $000	928,921	483,372
Bitumen reserves and contingent resources (millions of barrels, before royalties)(3)		
Proved (1P) reserves(4)	708	606
Probable reserves(5)	1,352	1,313
Proved plus probable (2P) reserves(4)(5)	2,060	1,919
Best estimate of contingent resources (2C)(6)(7)(8)	3,818	3,716

(1) Cash operating netbacks are calculated by deducting the related royalties and diluent, transportation, operating costs and realized gains/losses on financial derivatives from bitumen sales revenues, on a per barrel basis. Please refer to note 3 of the Operating Summary table within "Results of Operations."

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

(3) All reserve and resource volumes are from the GLJ Report.

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

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

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

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

(8) These volumes are the arithmetic sums of the Best Estimate Contingent resources for Christina Lake, Surmont and Growth Properties.

Bitumen production for 2011 averaged 26,605 bbls/d compared to 21,257 bbls/d in 2010. During the first half of 2010, the Corporation was ramping-up production from Phase 2 of the Christina Lake project towards its designed capacity of 25,000 bbls/d. The average steam to oil ratio ("SOR") in 2011 was 2.4 compared to an SOR of 2.5 in 2010. The SOR has remained relatively constant since May 2010 when the Phase 2 well pairs had progressed through the circulation phase and entered into normal operations. The success of the production ramp-up and improved SOR has enabled the Corporation to performance-test the integrated Phase 1 and 2 facilities and consistently exceed the original plant design production capacity of 25,000 bbls/d since June 2010, with the exceptions of the months of September 2010 and September 2011, when scheduled plant turnarounds were carried out and production was reduced.

Operating costs in 2011 averaged $15.46 per barrel compared to $19.89 per barrel in 2010. The decrease in operating costs per barrel in 2011 reflects the higher production volumes and lower costs during the first half of the year as compared to the same period in 2010, when production from Christina Lake was moving through the production ramp-up phase. After including the contribution of $4.50 per barrel from power sales, net operating costs decreased to $10.96 per barrel in 2011 from $16.13 per barrel in 2010. Power sales had the effect of recovering 88% of energy operating costs in 2011 as compared to 58% for 2010.

Cash operating netback in 2011 was $43.15 per barrel compared to $30.92 per barrel in 2010. The increase in cash operating netbacks is due mainly to higher bitumen production and realizations, lower operating costs, and higher realized power prices.

Net income for 2011 was $63.8 million compared to net income of $49.6 million for 2010. The increase in net income for 2011 was primarily attributable to:

- Cash operating netback increased to $418.7 million from $240.3 million primarily due to higher bitumen production and pricing in 2011 as compared to 2010;
- Depletion and depreciation expense increased from $97.9 million in 2010 to $124.3 million in 2011, primarily as a result of increased production;
- General and administrative expense increased from $36.4 million in 2010 to $55.7 million in 2011 as a result of higher staffing levels as the Corporation prepares to develop future phases of the Christina Lake project, the Surmont project and MEG's Growth Properties;
- Stock-based compensation expense increased from $12.5 million in 2010 to $21.4 million in 2011 primarily as a result of higher staffing levels and the increase in the Corporation's share price, as measured at the time of stock-based compensation grants;
- Net foreign exchange gain (loss) decreased from a net gain of $49.1 million in 2010 to a net loss of $35.7 million in 2011, primarily due to the weakening of the Canadian dollar over the period combined with increased U.S. dollar denominated long-term debt;
- Deferred income tax expense increased from $12.1 million in 2010 to $45.8 million in 2011 primarily as a result of increased income before income taxes.

Operating earnings for 2011 were $109.3 million compared to $2.5 million for 2010. The increase in operating earnings is primarily the result of higher bitumen production and realizations, lower operating costs, and higher realized power prices.

Cash flow from operations for 2011 totalled $304.6 million, compared to $124.5 million for 2010. The increase was primarily the result of increased cash flows from higher bitumen production and pricing in 2011 compared to 2010.

The Corporation had a combined cash and short-term investment balance of $1,647 million and a long-term debt balance of $1,752 million as at December 31, 2011 compared to a combined cash and short-term investment balance of $1,392 million and a long-term debt balance of $968 million as at December 31, 2010. The increase in these balances is due primarily to the Corporation's issuance of US$750 million in senior unsecured notes during the first quarter of 2011 and the increase in cash flow from operations partially offset by capital investments during the past year.

Net capital cash investment increased from $483.4 million during 2010 to $928.9 million during 2011. The increase is due to increased investment on Christina Lake Phase 2B development, resource definition at Christina Lake, Surmont and the Growth Properties, and investment in the Access Pipeline.

NON-IFRS MEASUREMENTS

The following table reconciles the non-IFRS measurements "Operating earnings" and "Cash operating netback" to "Net income" and reconciles "Cash flow from operations" to "Net cash provided by operating activities", the nearest IFRS measures. Operating earnings is defined as net income as reported, excluding after-tax unrealized foreign exchange gains and losses, unrealized gains and losses on derivative liabilities and gain on modification of long-term debt. Cash flow from operations excludes debt modification costs and the net change in non-cash operating working capital, while the IFRS measurement "Net cash provided by operating activities" includes these items. Cash operating netback is comprised of petroleum and power sales less royalties, operating costs, cost of diluent and transportation costs.

	Year ended December 31	
Non-IFRS Measurements ($000)	**2011**	**2010**
Net income	63,837	49,558
Add (deduct):		
Unrealized foreign exchange (gains) losses, net of tax(1)	39,383	(44,619)
Unrealized loss (gain) on derivative liabilities, net of tax(2)	8,115	(2,468)
(Gain) on modification of long-term debt, net of tax(3)	(2,080)	-
Operating earnings	109,255	2,471
Add (deduct):		
Interest income	(18,786)	(7,933)
Depletion and depreciation	124,327	97,881
General and administrative	55,738	36,403
Stock-based compensation	21,355	12,486
Research and development	6,810	5,384
Interest expense	73,647	51,612
Accretion	1,646	742
Realized loss (gain) on foreign exchange	506	1,686
Realized loss on derivative liabilities	532	34,412
Deferred income taxes, operating	43,682	5,171
Cash operating netback	418,712	240,315

Net cash provided by operating activities	314,302	74,382
Add (deduct):		
Net change in non-cash operating working capital items	(18,098)	50,143
Debt modification costs	8,423	-
Cash flow from operations	304,627	124,525

(1) Unrealized foreign exchange gains and losses result primarily from the translation of U.S. dollar denominated long-term debt, cash and cash equivalents to period-end exchange rates. Unrealized foreign exchange gains and losses are presented net of deferred tax expense of $4,176 for the year ended December 31, 2011 (deferred tax expense of $6,123 for the year ended December 31, 2010).

(2) Unrealized losses (gains) on derivative liabilities result from the interest rate floor on the Corporation's long-term debt and interest rate swaps entered into to fix a portion of its variable rate long-term debt, net of a deferred tax recovery of $2,704 for the year ended December 31, 2011 (deferred tax expense of $821 for the year ended December 31, 2010).

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

SUMMARY OF QUARTERLY RESULTS

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

($ millions, except per share amounts)	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	2010 Q3	2010 Q2	2010 Q1
Revenue	325.2	175.3	279.2	253.6	242.6	152.5	209.6	125.6
Net income (loss)	91.1	(115.2)	42.5	45.4	61.3	21.2	(34.8)	1.9
Per share – basic	0.47	(0.60)	0.22	0.24	0.32	0.12	(0.21)	0.01
Per share – diluted	0.46	(0.60)	0.21	0.23	0.31	0.11	(0.21)	0.01

Revenue for the eight most recent quarters has increased primarily due to higher production and pricing. In the first quarter of 2010, production averaged 13,398 bbls/d and increased to 27,826 bbls/d by the second quarter of 2011. Lower revenues in the third quarter of 2011 and 2010 were due to production being reduced as the result of scheduled turnarounds at the Christina Lake facilities for equipment cleaning and inspection. Following the turnarounds, production averaged 30,032 bbls/d during the fourth quarter of 2011 and 27,744 bbls/d during the same period of 2010.

Net income during the periods noted was impacted by:

- Foreign exchange gains and losses attributable to fluctuations in the rate of exchange between the Canadian and U.S. dollar in translating the Corporation's U.S. dollar denominated debt (net of U.S. dollar denominated cash and short-term investments);
- Changes in the fair value of the London Interbank Offered Rate ("LIBOR") floor on the senior secured term loans (embedded derivative liability);
- Risk management activities for interest rate swaps;
- Net gains and losses on the modification of long-term debt;
- The scheduled plant turnarounds performed in September 2010 and September 2011; and
- The ramp-up of Christina Lake Phase 2 operations throughout the first half of 2010.

BUSINESS ENVIRONMENT

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

	Year ended December 31		2011				2010			
	2011	2010	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Commodity Prices (Average Prices)										
Crude oil prices										
West Texas Intermediate (WTI) US$/bbl	95.12	79.53	94.06	89.76	102.56	94.10	85.18	76.20	78.03	78.71
Western Canadian Select (WCS)C$/bbl	77.15	67.23	85.53	70.68	82.17	70.23	67.87	62.94	65.60	72.51
Differential – WTI/WCS (C$/bbl)	16.95	14.69	10.70	17.31	17.08	22.55	18.35	16.24	14.59	9.42
Differential – WTI/WCS (%)	18.0%	17.9%	11.1%	19.7%	17.2%	24.0%	21.0%	20.5%	18.2%	11.5%
Natural gas prices										
AECO (C$/mcf)	3.66	4.11	3.45	3.70	3.72	3.76	3.56	3.70	3.84	5.33
Electric power prices										
Alberta power pool average price (C$/MWh)	76.17	50.91	76.05	94.69	51.90	82.03	45.95	35.77	81.15	40.78
Foreign exchange rates										
C$ equivalent of 1 US$ - average	0.9893	1.0301	1.0231	0.9802	0.9676	0.9860	1.0128	1.0391	1.0276	1.0409
C$ equivalent of 1 US$ - period end	1.0170	0.9946	1.0170	1.0389	0.9643	0.9718	0.9946	1.0298	1.0606	1.0156

WTI is an important benchmark for Canadian crude as it reflects onshore North American prices and its Canadian dollar equivalent is the basis for determining royalties on the Corporation's bitumen revenues. The WTI benchmark price averaged US$95.12 per barrel in 2011 compared to US$79.53 per barrel in 2010.

WCS is a blended heavy oil, consisting of heavy conventional and bitumen crude oils blended with sweet synthetic and condensate diluents. WCS trades at a discount to the WTI benchmark price. The WTI/WCS differential averaged $16.95 per barrel in 2011 compared to $14.69 per barrel in 2010. The wider differential in 2011 is primarily due to pipeline delivery restrictions arising from two, third party owned export pipeline breaks in late 2010. Accumulated inventories of heavy oil in Western Canada resulted in a temporary oversupply in the market and a corresponding decrease in WCS pricing relative to WTI, particularly during the first quarter of 2011. The differential during the fourth quarter of 2011 narrowed significantly due to increased market demand for heavy oil.

Natural gas is a primary energy input cost for the Corporation as it is used to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facility. The benchmark AECO natural gas price averaged $3.66 per mcf in 2011 compared to $4.11 per mcf in 2010. Natural gas prices have remained relatively low over the past three years as a result of strong supply growth in the United States.

The Alberta power pool price averaged $76.17 per megawatt hour for 2011 compared to $50.91 per megawatt hour in 2010. Power prices in 2011 were higher than in 2010 due to the closure of aging coal-fired power generation plants, power plant outages and demand growth. The Corporation's average realized power price will vary in comparison to the average monthly Alberta power pool price due to fluctuations in the Corporation's actual power generation levels throughout the month.

After strengthening relative to the U.S. dollar during the first seven months of 2011, the Canadian dollar weakened during the remaining months. As at December 31, 2011, the Canadian dollar had lost approximately $0.02 in value against the U.S. dollar compared to its value as at December 31, 2010. A decrease in the value of the Canadian dollar relative to the U.S. dollar has a positive impact on the Corporation's bitumen revenues, as the sales price is determined by reference to U.S. benchmarks. The positive impact of a weaker Canadian dollar on bitumen revenues is partially offset by higher principal and interest payments on the Corporation's U.S. dollar denominated debt.

RESULTS OF OPERATIONS

Production averaged 26,605 bbls/d in 2011 compared to 21,257 bbls/d in 2010. The average SOR for 2011 was 2.4 compared to 2.5 for 2010. The SOR for 2010 was impacted by the Christina Lake Phase 2 production ramp up period, during which a higher SOR is typically expected. 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 SAGD process.

The Corporation's 85 megawatt ("MW") cogeneration facility produces approximately 70% of the steam for current SAGD operations. MEG's Christina Lake facilities are utilizing the steam produced by the cogeneration facility and approximately 10 to 12 MW of the power generated. Surplus power is sold into the Alberta power pool.

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

Operating Summary

	Year ended December 31	
Cash operating netback ($000)	**2011**	**2010**
Blend sales(1)	1,021,036	717,610
Cost of diluents(2)	(451,009)	(322,923)
Bitumen sales	570,027	394,687
Transportation	(13,476)	(12,480)
Royalties	(31,438)	(16,521)
Net bitumen revenue	525,113	365,686
Operating costs – energy	(49,867)	(50,288)
Operating costs – non-energy	(100,162)	(104,280)
Power sales	43,628	29,197
Cash operating netback(3)	418,712	240,315

	Year ended December 31	
Production and sales volume summary (bbls/d)	**2011**	**2010**
Blend sales(1)	38,836	31,192
Diluents(2)	(12,249)	(9,900)
Bitumen sales	26,587	21,292
Change in inventory	18	(35)
Total bitumen production	26,605	21,257
Power sales (MWh)	586,938	585,476
Power price (C$/MWh)	74.33	49.87
Steam to oil ratio	2.4	2.5

	Year ended December 31	
Cash operating netback ($ per barrel)	**2011**	**2010**
Bitumen sales	58.74	50.79
Transportation	(1.39)	(1.61)
Royalties	(3.24)	(2.13)
Net bitumen revenue	54.11	47.05
Operating costs – energy	(5.14)	(6.47)
Operating costs – non-energy	(10.32)	(13.42)
Power sales	4.50	3.76
Cash operating netback(3)	43.15	30.92

(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, 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 sales volumes. Netbacks do not have a standardized meaning prescribed by IFRS and, therefore, may not be comparable to similar measures used by other companies. This non-IFRS measurement is widely used in the oil and gas industry as a supplemental measure of the Corporation's efficiency and its ability to fund future growth through capital expenditures. "Cash operating netback" is reconciled to "Net income" the nearest IFRS measure, under the heading "Non-IFRS Measurements".

Blend sales in 2011 were $1,021.0 million compared to $717.6 million in 2010. The increase in blend sales for 2011 is due to increased production as a result of the successful ramp-up of Christina Lake Phase 2 operations combined with higher average prices in 2011 compared to 2010. WTI averaged US$95.12 per barrel (C$94.10 per barrel) during 2011 compared to US$79.53 per barrel (C$81.93 per barrel) during 2010.

The cost of diluent in 2011 was $451.0 million compared to $322.9 million in 2010. The increase in the cost of diluent in 2011 is due to the increased production as a result of the successful ramp-up of Christina Lake Phase 2 operations combined with higher average prices in 2011 compared to 2010. Diluent costs averaged $100.87 per barrel, a premium of 107.2% compared to WTI, in 2011, compared to $89.37 per barrel, a premium of 109.1% compared to WTI, in 2010.

Transportation costs in 2011 were $13.5 million compared to $12.5 million in 2010 and averaged $1.39 per barrel in 2011 compared to $1.61 per barrel in 2010. Transportation costs per barrel in 2011 decreased as fixed costs were spread over higher production volumes during the year compared to 2010.

Royalties in 2011 were $31.4 million compared to $16.5 million in 2010 and averaged $3.24 per barrel during 2011 compared to $2.13 per barrel during 2010. The increase in total royalties from 2010 was due to the increase in production volumes and the price of WTI in 2011. The Corporation's royalty expense is based on price-sensitive royalty rates set by the Government of Alberta. The pre-payout royalty rate applicable to the Corporation's oil sands operations starts at 1% of bitumen revenues and increases for every dollar that the WTI crude oil price in Canadian dollars is priced above $55 per barrel, to a maximum of 9% when the WTI crude oil price is $120 per barrel or higher.

Operating costs in 2011 were $150.0 million compared to $154.6 million in 2010. Included in operating costs are $8.8 million for a scheduled plant turnaround in 2011 ($4.9 million in 2010). Operating costs decreased to $15.46 per barrel in 2011 from $19.89 per barrel in 2010. During the first half of 2010, non-energy operating costs were higher during the initial ramp-up of Christina Lake Phase 2 operations as the Corporation worked through the normal processing and treating issues associated with the ramp-up of the Phase 2 facilities.

Power sales in 2011 were $43.6 million compared to $29.2 million in 2010. The Corporation realized an average power price of $74.33 per megawatt hour in 2011 compared to $49.87 per megawatt hour in 2010. Power prices in 2011 were higher than 2010 due to the closure of aging coal-fired power generation plants, power plant outages and demand growth. The variations in the Corporation's realized power prices in 2011 compared to 2010 are largely consistent with the variations in the Alberta power pool prices during the periods noted.

Depletion and Depreciation

Depletion and depreciation expense totalled $124.3 million in 2011 compared to $97.9 million in 2010. The increase is primarily due to increased production in 2011 compared to 2010. In addition, $5.5 million of capital costs associated with derecognizing a SAGD production well that required replacement have been included in depletion and depreciation expense in 2011 (December 31, 2010 - nil). The Corporation's producing oil sands properties are depleted on a unit of production basis based on estimated proved reserves. Major facilities and equipment are depreciated on a unit of production basis over the estimated total productive capacity of the facilities and equipment. Pipeline assets are depreciated on a straight-line basis over their estimated useful lives. The depletion and depreciation rate was $12.81 per barrel in 2011 compared to $12.62 per barrel in 2010.

General and Administrative Costs

	Year ended December 31	
($000)	2011	2010
General and administrative costs	69,861	47,661
Capitalized salaries and benefits	(14,123)	(11,258)
General and administrative expense	55,738	36,403

General and administrative expense was $55.7 million in 2011 compared to $36.4 million in 2010. The increase in expense is primarily the result of the planned growth in the Corporation's professional staff and office costs to support the operation and development of its oil sands assets. Head office employee headcount grew from 178 as at December 31, 2010 to 231 at December 31, 2011. During 2011, the Corporation capitalized $14.1 million (2010 – $11.3 million) of salaries and benefits related to capital investments.

Stock-based Compensation

The fair value of compensation associated with the granting of stock options and restricted share units ("RSUs") to employees, contractors and directors is recognized by the Corporation in its financial statements. Fair value is determined using the Black-Scholes option pricing model. Stock-based compensation expense was $21.4 million in 2011 compared to $12.5 million in 2010. The increase in stock-based compensation expense is primarily the result of the additional expense related to RSUs which the Corporation began granting in September 2010, higher Black-Scholes valuations for the Corporation's stock options based on the increase in the Corporation's share price as measured at the time of stock-based compensation grants, the underlying volatility within the share price and the increase in the number of employees. The Corporation capitalizes a portion of the stock-based compensation expense associated with capitalized salaries and benefits. In 2011, the Corporation capitalized $5.1 million (2010 - $3.7 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, crude quality improvement and related technologies and have been expensed. Research and development expenditures were $6.8 million in 2011 compared to $5.4 million in 2010.

Interest Income

Interest income in 2011 was $18.8 million compared to $7.9 million in 2010. The increase is due to higher average investment balances and higher interest rates earned during 2011.

Gain on Debt Modification

The Corporation recognized a gain on debt modification of $2.8 million in 2011 related to the refinancing of the Corporation's senior secured term loans and revolving credit facilities on March 18, 2011. The gain consists of a $37.3 million gain on the derecognition of the 2% interest rate floor embedded derivative associated with the previous senior secured term loan D offset by a loss of $26.1 million on the derecognition of the discount on long-term debt associated with the interest rate floor embedded derivative and $8.4 million in fees related to the amendments to the senior secured term loans.

Net Foreign Exchange Gain (Loss)

	Year ended December 31	
($000)	2011	2010
Foreign exchange gain (loss) on:		
Long-term debt	(46,856)	52,186
Debt service reserve	-	(2,195)
US$ denominated cash and cash equivalents	11,649	(1,445)
Other	(506)	509
Net foreign exchange gain (loss)	(35,713)	49,055

Canadian $ - US$ exchange rate As at	December 31, 2011	December 31, 2010	December 31, 2009
C$ equivalent of 1 US$	1.0170	0.9946	1.0466

Net foreign exchange loss in 2011 was $35.7 million compared to a gain of $49.1 million in 2010. The net foreign exchange loss in 2011 was primarily due to the weakening of the Canadian dollar over the period combined with increased U.S. dollar denominated long-term debt. Effective March 18, 2011, the Corporation issued US$750.0 million of senior unsecured notes. During 2011, the Canadian dollar weakened in value against the U.S. dollar by approximately $0.02 compared to a strengthening of approximately $0.05 during 2010. The foreign exchange loss on long-term debt for the year was partially offset by a higher average U.S. dollar cash balance in 2011.

Net Finance Expense

	Year ended December 31	
($000)	2011	2010
Total interest expense	88,276	69,021
Less capitalized interest	(14,629)	(17,409)
Net interest expense	73,647	51,612
Accretion on decommissioning provisions	1,646	742
Unrealized fair value loss on embedded derivative liabilities	8,346	9,341
Unrealized fair value loss (gain) on interest rate swaps	2,473	(32,671)
Realized loss on interest rate swaps	532	34,412
Amortization of unrealized loss from accumulated other comprehensive income	-	20,041
Net finance expense	86,644	83,477

Total interest expense in 2011 was $88.3 million compared to $69.0 million in 2010. Total interest expense in 2011 increased compared to the same period in 2010 primarily due to the increase in total debt balance outstanding in 2011 partially offset by lower interest rates. Effective March 18, 2011, the Corporation issued US$750.0 million of senior unsecured notes.

The loss on embedded derivative liabilities was $8.3 million in 2011 compared to a loss of $9.3 million in 2010. These losses relate to the change in fair value of the interest rate floor associated with the Corporation's senior secured credit facilities. The interest rate floor is considered an embedded derivative as the floor rate was higher than the LIBOR at the time that the debt agreement was entered into. Accordingly, the original fair value of the embedded derivative at the time the debt agreement was entered into was netted against the carrying value of the long-term debt and will be amortized over the life of the debt agreement. The fair value of the embedded derivative is included in financial derivative liabilities on the balance sheet and gains and losses associated with changes in the fair value of the embedded derivative are included in net finance expense.

The Corporation has entered into interest rate swap contracts to fix the interest rate at 4.6% on US$748 million of the US$1.0 billion senior secured term loan until September 30, 2016. US$300 million was effective September 30, 2011, US$150 million was effective December 31, 2011, US$150 million was effective January 12, 2012, and US$148 million was effective January 27, 2012. In 2011, the Corporation realized a $0.5 million loss on interest rate swap contracts and recognized an unrealized loss of $2.5 million on these contracts.

In 2010, the Corporation recognized a realized loss on interest rate swap contracts of $34.4 million and an unrealized gain of $32.7 million. The Corporation had previously hedged, through December 31, 2010, the interest rate on US$700 million of its floating rate debt by swapping LIBOR for an average fixed rate of 5.05%.

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

Income Taxes

Deferred income tax expense in 2011 was $45.8 million compared to $12.1 million in 2010. The increase in deferred income tax expense in 2011 compared to 2010 relates primarily to the increase in income before income taxes.

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

- The non-taxable portion of capital foreign exchange gains and losses on the translation of U.S. dollar denominated debt. In 2011, the non-taxable foreign exchange loss was $23.4 million compared to a non-taxable gain of $26.2 million in 2010.
- During 2011, the Corporation did not recognize the tax benefit of $28.5 million of unrealized taxable capital foreign exchange losses.
- Non-taxable stock-based compensation in 2011 was $21.3 million compared to $12.5 million in 2010.

The Corporation is not currently taxable. As of December 31, 2011, the Corporation had approximately $3.1 billion of available tax pools and had recognized a deferred income tax liability of $68.0 million. In addition, at December 31, 2011, the Corporation had $887.8 million of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

CAPITAL INVESTING

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

	Year ended December 31	
Summary of capital investment ($000)	2011	2010
Property, plant and equipment :		
Christina Lake Project:		
Resource exploration and delineation	48,168	25,836
Horizontal drilling	119,633	36,910
Facilities, procurement and construction	626,051	250,274
Total Christina Lake Project	793,852	313,020
Access Pipeline	44,590	-
Stonefell Terminal	10,329	42,504
Capitalized interest and fees	14,629	17,409
Other	15,434	28,124
Property, plant and equipment	878,834	401,057
Exploration and evaluation assets	45,639	74,344
Other intangible assets	4,448	7,971
Total cash investments	928,921	483,372
Non-cash investments	55,705	5,657
Total capital investment	984,626	489,029

The Corporation's capital cash investments totalled $928.9 million in 2011 compared with $483.4 million of capital cash investment in 2010. Capital investment in 2011 focused on Christina Lake Phase 2B development and resource delineation at Christina Lake, Surmont and the Growth Properties and expansion of the Access Pipeline.

Property, Plant and Equipment

During 2011 the Corporation drilled 87 core holes, four observation wells and one water source well to support Phase 2B horizontal well placement and to further delineate the resource base at Christina Lake. The horizontal drilling program for Phase 2B was initiated in the fourth quarter of 2010 and as at December 31, 2011, a total of 31 of the 84 planned horizontal wells have been drilled. Facilities, procurement and construction investment during 2011 has been directed towards Phase 2B detailed engineering and the purchase of major equipment and materials. As at December 31, 2011, approximately $710 million of the estimated $1.4 billion project cost has been invested and approximately 60% of the total budget is locked in. As at December 31, 2011, detailed engineering was 93% complete. All materials and project modules have been ordered, with delivery and on-site construction scheduled to continue through 2012 with completion targeted in 2013.

During 2011, the Corporation invested $44.6 million on the expansion of the Access Pipeline's pumping capacity and on connections to other pipeline systems.

In 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. During 2011, the Corporation invested $10.3 million on the construction of the Stonefell Terminal.

The Corporation capitalizes interest expense and amortization of deferred finance charges for undeveloped property acquisitions and major development projects. Interest associated with growth capital projects, including Phase 2B and Phase 3, are being capitalized. In addition, interest associated with certain infrastructure capital projects is capitalized. During 2011, the Corporation capitalized $14.6 million of interest and finance charges compared to $17.4 million in 2010.

Other capital investments are comprised of capitalized salaries and benefits, investment in leasehold improvements and tangible assets for the Corporation's offices.

Exploration and Evaluation Assets

The Corporation invested a total of $45.6 million in 2011 to drill 50 core holes on the Growth Properties and four core holes on the Surmont leases. These core holes were used to increase resource definition on the Growth Properties and to increase resource definition and test water quality on the Surmont leases in order to build an inventory of potential commercial projects.

Other Intangible Assets

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

Non-cash

Non-cash capital investment in 2011 includes $51.8 million for decommissioning the Corporation's wells and facilities. The 2011 decommissioning investment is comprised of $24.9 million for changes in the estimated future cash outflows related to the Corporation's existing assets, $25.4 million for capital investments incurred during the year and $1.5 million for assets acquired.

SHARES OUTSTANDING

As at February 17, 2012, the Corporation had the following share capital instruments outstanding:

Common shares	193,860,088
Convertible securities	
Stock options outstanding – exercisable and unexercisable	9,799,935
Restricted share units outstanding	553,164

OUTLOOK

The Corporation anticipates that annual bitumen production volumes for 2012 will be in the range of 26,000 to 28,000 bbls/d, after including the impact of a planned three-week shutdown in September 2012. The planned shutdown will be used to tie-in infrastructure related to Christina Lake Phase 2B and to perform regular plant maintenance. Following the shutdown, production is expected to ramp-up toward exit rates of 29,000 to 31,000 bbls/d by the end of the year. Non-energy operating costs are anticipated to be in the range of $10 to $12 per barrel.

The Corporation's 2012 capital budget includes planned investment of approximately $1.37 billion focused on MEG's strategic plan of growing bitumen production capacity to 260,000 bbls/d by 2020. Approximately $930 million of the total capital budget will be directed towards growth-focused investment, with the majority of the funds used to advance construction of Christina Lake Phase 2B. Infrastructure spending of approximately $220 million will go towards enhancing the Corporation's strategic marketing hub in the Edmonton area. This will include regulatory and engineering work related to the proposed expansion of the jointly-owned Access Pipeline and completion of the Stonefell Terminal. The remainder of the growth-focused investment will be directed towards assessment of Phase 2B enhancement opportunities, front-end engineering and initial material orders for Christina Lake Phase 3 and investment in seismic and delineation drilling at Christina Lake, Surmont and the Corporation's Growth Properties to support future growth.

LIQUIDITY AND CAPITAL RESOURCES

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

As of December 31, 2011, the Corporation's capital resources included $1.5 billion of working capital and a US$500 million revolving credit facility. Working capital is comprised of $1.6 billion of cash, cash equivalents and short-term investments, offset by a non-cash working capital deficiency of $0.1 billion.

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

Cash Flows Summary

	Year ended December 31	
($000)	2011	2010
Net cash provided by (used in)		
Operating activities	314,302	74,382
Investing activities	(813,783)	(473,323)
Financing activities	758,517	661,814
Foreign exchange gains and (losses) on cash and cash equivalents held in foreign currency	11,649	(1,445)
Change in cash and cash equivalents	270,685	261,428

Cash Flows - Operating Activities

Net cash provided by operating activities in 2011 was $314.3 million compared to $74.4 million in 2010. The increase in cash flows from operating activities is due mainly to the increase in cash provided from higher bitumen production and higher prices during 2011 compared to 2010. Cash flow from operating activities was also impacted by the net change in non-cash working capital. Non-cash operating activities resulted in a net increase in cash from operating activities of $18.1 million in 2011 compared to a net decrease of $50.1 million in 2010.

Cash Flows - Investing Activities

Net cash used for investing activities was $813.8 million in 2011 compared to $473.3 million in 2010. The change included an increase in non-cash investing working capital items of $114.2 million in 2011, compared to a decrease of $108.6 million in 2010. The increases in non-cash investing working capital items in 2011 relate primarily to the changes in short-term investment balances and trade payables related to capital items. Refer to the "CAPITAL INVESTING" section of this MD&A for further details.

Cash Flows - Financing Activities

Financing activities in 2011 consisted of $723.8 million in net proceeds from the Corporation's issuance of US$750.0 million senior unsecured notes in the first quarter of 2011, $39.7 million of proceeds received from the exercise of stock options and $2.5 million of debt principal repayment on the senior secured loan.

On March 18, 2011, the Corporation refinanced its existing senior secured term loans and revolving credit facilities. Under the terms of the agreement, the Corporation increased its borrowings under the senior secured credit facilities from US$999.4 million to US$1.0 billion and increased the borrowing capacity under its revolving credit facility from US$200 million to US$500 million. The new term loan bears a floating interest rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 200 or 300 basis points, respectively, and an interest rate floor of 200 basis points based on U.S. Prime or 100 basis points based on LIBOR. The term loan is to be repaid in quarterly installment payments equal to 0.25% of the original outstanding balance beginning on December 31, 2011, with the balance due on March 18, 2018. The Corporation also extended the maturity date of its revolving credit facility to March 18, 2016 from January 31, 2013.

The Corporation periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. In order to mitigate a portion of this risk, the Corporation has entered into interest rate swap contracts to fix the interest rate at 4.6% on US$748 million of the US$1.0 billion senior secured term loan until September 30, 2016.

In addition to amendments to the existing borrowing facilities, on March 18, 2011 the Corporation issued US$750.0 million in aggregate principal amount of 6.5% senior unsecured notes, with interest paid semi-annually. The notes are due on March 15, 2021.

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)	1,777,208	10,145	20,290	20,290	1,726,483
Interest on long-term debt(1)	701,607	90,157	179,094	177,467	254,8890
Asset retirement obligation(2)	179,064	-	500	-	178,564
Pipeline transportation(3)	1,431,259	-	31,088	93,435	1,306,736
Contracts and purchase orders(4)	624,970	563,980	45,768	15,222	-
Operating leases(5)	114,999	8,121	18,740	19,481	68,657
	4,829,107	672,403	295,480	325,895	3,535,329

(1) This represents the scheduled principal repayment of the senior secured credit facility and the senior unsecured notes and associated interest payments based on interest rates in effect on December 31, 2011.
(2) This represents the undiscounted future obligation associated with the decommissioning of the Corporation's oil and gas properties and facilities.
(3) This represents a take-or-pay commitment for 25,000 bpd from 2014 – 2015, 50,000 bpd from 2016 – 2019, and 100,000 bpd from 2020 – 2028.
(4) This represents the future commitment associated with the construction of the Christina Lake Phase 2B facility, capital equipment maintenance and purchases, and diluent purchases.
(5) This represents the future commitment for the Calgary corporate office.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

Property, Plant and Equipment

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

Exploration Assets

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

Asset Impairments

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

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

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

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

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

Bitumen Reserves

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

Decommissioning Provisions

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

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

In connection with the Corporation's review and third party reviews of the decommissioning obligation during 2011, the Corporation increased the estimated obligation to $179.3 million from the previous estimate of $37.3 million. The increase was primarily due to the $65.5 million change in estimated costs related to its existing facilities and wells and $76.5 million incurred on the construction of Phase 2B and related infrastructure facilities. The Corporation has estimated the net present value of the future total obligation to be $65.4 million as at December 31, 2011 (December 31, 2010 - $12.6 million) at a discount factor of 5.4% (December 31, 2010 – 6.8%). This obligation is estimated to be settled in periods up to 2057.

Income Taxes

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

Stock-based Compensation

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

Derivative Financial Instruments

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

TRANSACTIONS WITH RELATED PARTIES

The Corporation did not enter into any related party transactions during the years ended December 31, 2011 or December 31, 2010, other than compensation of key management personnel. The Corporation considers directors and executive officers as key management personnel.

	2011	2010
Salaries and short-term employee benefits	7,254	6,624
Share-based compensation expense	8,015	4,072
	15,269	10,696

OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2011 and December 31, 2010, the Corporation did not have any off-balance sheet arrangements.

NEW ACCOUNTING POLICIES

International Financial Reporting Standards ("IFRS")

In February 2008, the Canadian Accounting Standards Board confirmed that IFRS will be used for interim and annual financial statements of publicly accountable enterprises effective for fiscal years beginning on or after January 1, 2011. Accordingly, the Corporation has commenced reporting on an IFRS basis. Comparative information for periods from January 1, 2010 onwards has been restated in accordance with IFRS.

Accounting standards issued but not yet applied

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

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

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

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

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

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

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

IAS 19 has been amended to make significant changes to the recognition and measurement of defined benefit pension expense and termination benefits and to enhance the disclosure of all employee benefits. A number of other amendments have been made to recognition, measurement and classification including redefining short-term and other long-term benefits, guidance on the treatment of taxes related to benefit plans, guidance on risk/cost sharing features, and expanded disclosures.

In addition, there have been amendments to existing standards, including IAS 27, Separate Financial Statements, and IAS 28, Investments in Associates and Joint Ventures. IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 – 13.

RISK FACTORS

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

Risks Arising From Construction Activities

Cost and Schedule Risk

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

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

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

Risks Arising From Operations

Operating Risk

The operation of the Corporation's oil sands properties and projects are and will continue to be subject to the customary hazards 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 or electricity prices;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher steam-to-oil ratios;
- a lack of access to or an increase in the cost of diluent;
- an increase in the cost of natural gas;
- the reliability and maintenance of the Access Pipeline and MEG's other facilities;
- the need to repair existing horizontal wells, or the need to drill additional horizontal wells;
- the ability and cost to transport bitumen, diluent and bitumen diluent blends, and the cost to dispose of certain by-products;
- increased royalty payments resulting from changes in the regulatory regime;
- the cost of labour, materials, services and chemicals used in MEG's operations; and
- the cost of compliance with existing and new regulations.

Labour Risk

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

Project Development Risks

Reliance on Third Parties

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

Commodity Price Risk

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

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

Interest Rate Risk

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

Foreign Currency Risk

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

Regulatory and Environmental Risk

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

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

Royalty Risk

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

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

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

Third Party Risks

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

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

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

DISCLOSURE CONTROLS AND PROCEDURES

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the 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 IFRS. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's internal controls over financial reporting at the financial year end of the 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, 2011 that have materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

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

ADDITIONAL INFORMATION

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

QUARTERLY OPERATING SUMMARY (UNAUDITED)

($/bbl unless specified)	2011				2010			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Bitumen sales	67.99	51.79	62.78	49.57	51.10	51.18	47.77	55.12
Transportation	(1.19)	(1.93)	(1.18)	(1.42)	(1.26)	(1.27)	(1.46)	(3.10)
Royalties	(3.66)	(2.82)	(3.69)	(2.64)	(2.27)	(1.94)	(1.87)	(2.56)
Net bitumen revenue	63.14	47.04	57.91	45.51	47.57	47.97	44.44	49.46
Operating costs – energy	(4.61)	(5.05)	(5.39)	(5.54)	(4.87)	(5.29)	(5.95)	(12.55)
Operating costs – non-energy	(8.55)	(17.20)	(8.74)	(8.68)	(9.02)	(14.76)	(11.89)	(23.48)
Power sales	4.66	5.13	2.77	5.59	2.88	2.15	5.24	5.22
Cash operating netback	54.64	29.92	46.55	36.88	36.56	30.06	31.84	18.65
Blend Sales	77.81	65.86	76.51	65.69	63.95	60.80	60.94	68.06
Differential – WTI//Blend	18.42	22.13	22.73	27.09	22.27	18.33	19.25	13.88
Differential – WTI/Blend (%)	19.1%	25.2%	22.9%	29.0%	25.8%	23.2%	24.0%	16.9%
Diluent cost	98.72	101.06	107.00	97.47	89.95	83.46	86.20	88.56
Bitumen sales	67.99	51.79	62.78	49.57	51.10	51.18	47.77	55.12
Power price (C$/MWh)	78.91	93.33	46.95	82.40	44.91	35.34	78.12	38.57
Power sales (MWh)	164,342	104,168	149,554	168,874	163,198	108,664	149,956	163,658
Bitumen production bbls/d)	30,032	20,945	27,826	27,653	27,744	19,339	24,412	13,398
Bitumen sales (bbls/d)	30,268	20,591	27,860	27,666	27,648	19,376	24,562	13,447
Diluents usage (bbls/d)	14,223	8,229	12,550	14,073	13,316	7,825	11,874	6,533
Blend sales (bbls/d)	44,491	28,820	40,410	41,703	40,964	27,201	36,436	19,980

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 International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and include certain estimates that reflect Management's best judgments. Financial information contained throughout the annual report is consistent with these financial statements.

The Corporation maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Corporation's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that our internal controls over financial reporting were effective as of December 31, 2011.

The Corporation's Board of Directors has approved 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 and for the year ended December 31, 2011. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the financial statements.

W. J. McCaffrey

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

Dale J. Hohm, CA
Chief Financial Officer

February 23, 2012

Auditor's Report

AUDITOR'S REPORT TO THE SHAREHOLDERS

February 23, 2012

To the Shareholders of MEG Energy Corp.

We have audited the accompanying financial statements of MEG Energy Corp., which comprise the balance sheet as at December 31, 2011, December 31, 2010 and January 1, 2010 and the statements of comprehensive income, changes in shareholders equity and cash flow for the years ended December 31, 2011 and December 31, 2010, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, 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 audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits 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, 2011 and December 31, 2010 and January 1, 2010 and its financial performance and its cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

Financial Statements

BALANCE SHEET

(Expressed in thousands of Canadian dollars)

As at	Note	December 31, 2011	December 31, 2010	January 1, 2010 Note 4(v)(e)
Assets				
Current assets				
Cash and cash equivalents	24	**$ 1,495,131**	$ 1,224,446	$ 963,018
Short-term investments		**151,938**	167,406	-
Trade receivables and other	7	**135,545**	97,567	34,424
Inventories	8	**9,207**	6,173	5,560
Debt service reserve	9	-	-	102,359
		1,791,821	1,495,592	1,105,361
Non-current assets				
Property, plant and equipment	10	**3,368,819**	2,566,474	2,257,025
Exploration and evaluation assets	11	**991,805**	937,986	862,703
Other intangible assets	12	**37,292**	33,158	24,613
Restricted cash	13	-	-	12,810
Other assets	14	**11,312**	10,055	11,746
Total assets		**$ 6,201,049**	$ 5,043,265	$ 4,274,258
Liabilities				
Current liabilities				
Trade payables	15	**$ 301,626**	$ 144,378	$ 71,842
Current portion of long-term debt	16	**10,145**	10,065	10,593
Current portion of provisions and other liabilities	17	**4,805**	15,454	47,020
		316,576	169,897	129,455
Non-current liabilities				
Long-term debt	16	**1,741,394**	957,999	1,015,816
Provisions and other liabilities	17	**91,006**	37,882	24,093
Deferred income tax liability	18	**67,969**	23,363	12,913
Total liabilities		**2,216,945**	1,189,141	1,182,277
Commitments and contingencies	26			
Shareholders' equity				
Share capital	19	**3,877,193**	3,820,446	3,136,563
Contributed surplus	19	**85,568**	76,172	62,501
Retained earnings (deficit)		**21,343**	(42,494)	(92,052)
Accumulated other comprehensive loss		-	-	(15,031)
Total shareholders' equity		**3,984,104**	3,854,124	3,091,981
Total liabilities and shareholders' equity		**$ 6,201,049**	$ 5,043,265	$ 4,274,258

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

These financial statements were approved by the Corporation's Board of Directors on February 23, 2012.

(Signed)
William (Bill) McCaffrey, Director

(Signed)
Robert B. Hodgins, Director

STATEMENT OF COMPREHENSIVE INCOME

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

Year ended December 31	Note	2011	2010
Petroleum revenue, net of royalties	20	**$ 989,598**	$ 701,089
Power revenue		**43,628**	29,197
		1,033,226	730,286
Diluent and transportation		**464,485**	335,403
Operating expenses		**150,029**	154,568
Depletion and depreciation	10, 12	**124,327**	97,881
General and administrative		**55,738**	36,403
Stock-based compensation	19	**21,355**	12,486
Research and development		**6,810**	5,384
		822,744	642,125
Revenues less operating expenses		**210,482**	88,161
Other income (expense)			
Interest income		**18,786**	7,933
Gain on debt modification		**2,773**	-
Foreign exchange (loss) gain, net		**(35,713)**	49,055
Net finance expense	21	**(86,644)**	(83,477)
		(100,798)	(26,489)
Income before income taxes		**109,684**	61,672
Deferred income tax expense	18	**(45,847)**	(12,114)
Net income		**63,837**	49,558
Other comprehensive income			
Amortization of balance in AOCI, net of taxes		-	15,031
Comprehensive income for the period		**$ 63,837**	$ 64,589
Earnings per share			
Basic	25	**$ 0.33**	$ 0.28
Diluted	25	**$ 0.32**	$ 0.27

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

STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

(Expressed in thousands of Canadian dollars)

	Note	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Accumulated Other Comprehensive (Loss) Income (AOCI)	Total Shareholders' Equity
Balance at January 1, 2011		**$ 3,820,446**	**$ 76,172**	**$ (42,494)**	**$ -**	**$ 3,854,124**
Stock options exercised	19	**52,037**	**(17,030)**			**35,007**
RSU's vested and released	19	**4,710**				**4,710**
Stock-based compensation	19		**26,426**			**26,426**
Net income				**63,837**		**63,837**
Balance at December 31, 2011		**$ 3,877,193**	**$ 85,568**	**$ 21,343**	**$ -**	**$ 3,984,104**
Balance at January 1, 2010		$ 3,136,563	$ 62,501	$ (92,052)	$ (15,031)	$ 3,091,981
Shares issued for cash		700,000				700,000
Share issue costs, net of tax of $9,174		(27,523)				(27,523)
Stock options exercised		11,406	(2,539)			8,867
Stock-based compensation			16,210			16,210
Net income				49,558		49,558
Other comprehensive income, net of tax:						
Amortization of balance in AOCI					15,031	15,031
Balance at December 31, 2010		$ 3,820,446	$ 76,172	$ (42,494)	$ -	$ 3,854,124

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

STATEMENT OF CASH FLOW

(Expressed in thousands of Canadian dollars)

Year ended December 31	Note	2011	2010
Cash provided by (used in):			
Operating activities			
Net income		**$ 63,837**	$ 49,558
Adjustments for:			
Depletion and depreciation	10, 12	**124,327**	97,881
Stock-based compensation	19	**21,355**	12,486
Unrealized loss (gain) on foreign exchange		**35,207**	(50,741)
Unrealized gain on derivative financial liabilities		**(378)**	(3,289)
Deferred income tax expense	18	**45,847**	12,114
Other		**6,009**	6,516
Net change in non-cash operating working capital items	24	**18,098**	(50,143)
Net cash provided by operating activities		**314,302**	74,382
Investing activities			
Capital investments		**(928,921)**	(483,372)
Change in debt service reserve		**-**	102,359
Changes in restricted cash		**-**	12,810
Other		**965**	3,522
Net change in non-cash investing working capital items	24	**114,173**	(108,642)
Net cash used in investing activities		**(813,783)**	(473,323)
Financing activities			
Issue of shares		**39,717**	672,170
Issue of long-term debt		**1,708,188**	-
Financing costs		**(3,025)**	-
Repayment of long-term debt		**(986,363)**	(10,356)
Net cash provided by financing activities		**758,517**	661,814
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**11,649**	(1,445)
Change in cash and cash equivalents		**270,685**	261,428
Cash and cash equivalents, beginning of period		**1,224,446**	963,018
Cash and cash equivalents, end of period	24	**$ 1,495,131**	$ 1,224,446
Cash interest paid		**$ 66,554**	$ 97,636
Cash interest received		**$ 18,786**	$ 7,933

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

NOTES TO FINANCIAL STATEMENTS

Year ended December 31, 2011

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

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the Alberta Business Corporations Act on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange ("TSX") under the symbol "MEG". The Corporation owns a 100% interest in over 900 sections of oil sands leases in the Athabasca region of northern Alberta and is primarily engaged in a steam assisted gravity drainage oil sands development at its 80 section Christina Lake Regional Project ("Christina Lake Project"). The Corporation is using a staged approach to development. The development includes co-ownership of Access Pipeline, a dual pipeline to transport diluent north from the Edmonton area to the Athabasca oil sands area and a blend of bitumen and diluent south from the Christina Lake Project into the Edmonton area. The Corporation's corporate office is located at 520 3rd Avenue S.W., Calgary, Alberta.

2. BASIS OF PRESENTATION AND ADOPTION OF IFRS

The Corporation prepares its financial statements in accordance with Canadian generally accepted accounting principles ("GAAP") as set out in Part I of the Handbook of the Canadian Institute of Chartered Accountants ("CICA Handbook"). In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards ("IFRS"), and require publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Accordingly, these are the Corporation's first annual financial statements prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). In these financial statements, the term "Canadian GAAP" refers to Canadian GAAP before the adoption of IFRS.

These financial statements have been prepared in accordance with IFRS. Subject to certain transitional elections disclosed in note 4, the Corporation has consistently applied the same accounting policies in its opening IFRS balance sheet at January 1, 2010 and throughout all periods presented, as if these policies had always been in effect. Note 4 discloses the impact of the transition to IFRS on the Corporation's reported financial position, financial performance and cash flows, including the nature and effect of significant changes in accounting p

3. SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of measurement

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

(b) Foreign currency translation

i. Functional and presentation currency

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

ii. Transactions and balances

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

(c) Significant accounting estimates and judgments

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

i. Carrying value of property, plant and equipment

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

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

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

ii. Exploration and evaluation assets

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

iii. Decommissioning costs

Decommissioning costs are incurred when certain of the Corporation's tangible long-lived assets are retired. Assumptions, based on current economic factors which management believes are reasonable, have been made to estimate the future liability. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. The impact to net income over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. In addition, management exercises judgment to determine the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors. At December 31, 2011, the credit-adjusted discount rate was 5.4% and a 1% increase in the discount rate would result in a $12.5 million decrease in the present value of the decommissioning provision.

iv. Impairment of assets

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

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

v. Compensation plans

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

vi. Deferred income tax

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

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

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

vii. Financial instruments

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

viii. Other assets

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.

(d) Joint venture operations

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

(e) Financial Instruments

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

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

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

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

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

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

ii. Loans and receivables

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

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

iii. Financial liabilities at amortized cost

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

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

iv. Derivative financial instruments

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

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

(f) Cash and cash equivalents

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

(g) Short-term investments

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

(h) Trade receivables and other

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

(i) Inventories

Product inventories consist of crude oil products and are valued at the lower of cost and net realizable value on a weighted average cost basis. Net realizable value is the estimated selling price less applicable selling expenses.

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

i. Recognition and measurement

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

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

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

Development and production items of property, plant and equipment, which include oil sands and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGU's for impairment testing. A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The Corporation's development and production assets are currently solely within the Christina Lake CGU. The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, was determined by reference to its historic cost less accumulated depletion and depreciation and accumulated impairment losses determined in accordance with IFRS. When significant parts of an item of property, plant and equipment, including oil sands and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

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

ii. Subsequent costs

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

iii. Depletion and depreciation

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

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

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

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

(k) Other intangible assets

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

(l) Leased assets

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

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

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

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

(m) Impairments

i. Financial assets

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

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

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

All impairment losses are recognized in income or loss.

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

ii. Non-financial assets

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

For the purpose of impairment testing, assets are grouped into CGU's. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell. E&E assets are assessed for impairment within the aggregation of all CGU's in that segment.

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

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in income or loss. Impairment losses recognized in respect of CGU's are allocated to reduce the carrying amounts of the assets in the CGU on a pro rata basis.

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

(n) Provisions

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

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

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

Changes in estimated decommissioning and site restoration liabilities that occurred before the transition to IFRS have been adjusted for at the transition date on a net basis in accordance with the applicable exemptions under IFRS 1.

(o) Deferred income taxes

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

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

(p) Share capital

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

(q) Share based payments

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

(r) Revenues

Petroleum revenue and royalty recognition: Revenue associated with the sale of 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.

Power revenue recognition: Revenue from power generated in excess of the Corporation's internal requirements is recognized when the power leaves the plant gate at the point at which the risks and rewards are transferred to the customer.

(s) Diluent and transportation

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

(t) Net finance expense

Finance expense is comprised of interest expense on borrowings, accretion of the discount on provisions, and fair value gains and losses on re-measurement of derivative financial instruments.

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

(u) Earnings per share

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

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

(v) Accounting standards issued but not yet applied

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

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

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

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

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

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

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

IAS 19 has been amended to make significant changes to the recognition and measurement of defined benefit pension expense and termination benefits and to enhance the disclosure of all employee benefits. A number of other amendments have been made to recognition, measurement and classification including redefining short-term and other long-term benefits, guidance on the treatment of taxes related to benefit plans, guidance on risk/cost sharing features, and expanded disclosures.

In addition, there have been amendments to existing standards, including IAS 27, Separate Financial Statements, and IAS 28, Investments in Associates and Joint Ventures. IAS 27 addresses accounting for subsidiaries, jointly controlled entities and associates in non-consolidated financial statements. IAS 28 has been amended to include joint ventures in its scope and to address the changes in IFRS 10 – 13.

4. TRANSITION TO IFRS

These financial statements for the year ended December 31, 2011 represent the Corporation's first annual financial statements prepared in accordance with IFRS, which are also generally accepted accounting principles for publicly accountable enterprises in Canada. The Corporation adopted IFRS in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards" and has prepared its financial statements with IFRS applicable for periods beginning on or after January 1, 2010, using significant accounting policies as described in Note 3. For all periods up to and including the year ended December 31, 2010, the Corporation prepared its financial statements in accordance with Canadian GAAP. This note explains the principal adjustments made by the Corporation to restate its Canadian GAAP Financial Statements on transition to IFRS.

i. Transition elections:

The Corporation has applied the following transition exceptions and exemptions to full retrospective application of IFRS:

Exemption	Application of exemption
Deemed cost of property, plant and equipment	The Corporation has elected to apply the exemption under IFRS allowing it to measure oil and gas assets at the date of transition to IFRS at the amount determined under an entity's previous GAAP.
Decommissioning provision included in the cost of property, plant and equipment	The exemption provided in IFRS 1 from the full retrospective application of IFRIC 1 has been applied and the difference between the carrying values of the Corporation's decommissioning provision as measured under IAS 37 and their carrying values under Canadian GAAP has been recognized directly in retained earnings.
Share-based payments	The Corporation has elected to apply the share-based payment exemption. It has applied IFRS 2 to those options that were issued after November 7, 2002 but that had not vested as of January 1, 2010.
Business combinations	The Corporation has applied the business combinations exemption in IFRS 1. It has not restated business combinations that took place prior to the January 1, 2010 transition date.
Lease transactions	The exemption provided in IFRS 1 from the full retrospective application of IFRIC 4 has been applied to determine whether an arrangement existing as at January 1, 2010 contains a lease based on the facts and circumstances existing at that date.
Borrowing costs	The Corporation has applied the borrowing cost exemption in IFRS 1. It has applied the requirements of IAS 23 to borrowing costs relating to qualifying assets as at January 1, 2010.

ii. Reconciliation of assets, liabilities and shareholders' equity

		December 31, 2010			January 1, 2010		
	Note 4v	CDN GAAP	ADJ	IFRS	CDN GAAP	ADJ	IFRS
Assets							
Current assets							
Cash and cash equivalents		$ 1,224,446	$ -	$ 1,224,446	$ 963,018	$ -	$ 963,018
Short-term investments		167,406	-	167,406	-	-	-
Trade receivables and other	c	96,964	603	97,567	33,662	762	34,424
Inventories		6,173	-	6,173	5,560	-	5,560
Debt service reserve		-	-	-	102,359	-	102,359
		1,494,989	603	1,495,592	1,104,599	762	1,105,361
Non-current assets							
Property, plant and equipment	a,c,e,j	3,515,150	(948,676)	2,566,474	3,144,341	(887,316)	2,257,025
Exploration and evaluation assets	a	-	937,986	937,986	-	862,703	862,703
Other intangible assets	a	-	33,158	33,158	-	24,613	24,613
Restricted cash		-	-	-	12,810	-	12,810
Other assets	c	7,492	2,563	10,055	7,743	4,003	11,746
Total assets		**$ 5,017,631**	**$ 25,634**	**$ 5,043,265**	**$ 4,269,493**	**$ 4,765**	**$ 4,274,258**
Liabilities							
Current liabilities							
Trade payables		$ 144,378	$ -	$ 144,378	$ 71,842	$ -	$71,842
Current portion of long-term debt		10,065	-	10,065	10,593	-	10,593
Current portion of provisions and other liabilities	b	-	15,454	15,454	-	47,020	47,020
Current portion of derivative financial liabilities		-	-	-	32,671	(32,671)	-
Current portion of deferred lease inducements		292	(292)	-	-	-	-
		154,735	15,162	169,897	115,106	14,349	129,455
Non-current liabilities							
Long-term debt	b,c,d	969,933	(11,934)	957,999	1,029,687	(13,871)	1,015,816
Provisions and other liabilities	b,e	-	37,882	37,882	-	24,093	24,093
Deferred lease inducements		3,185	(3,185)	-	-	-	-
Asset retirement obligations		16,793	(16,793)	-	14,297	(14,297)	-
Deferred income tax liability	f	22,238	1,125	23,363	14,290	(1,377)	12,913
Total liabilities		1,166,884	22,257	1,189,141	1,173,380	8,897	1,182,277
Shareholders' equity							
Share capital	g	3,821,579	(1,133)	3,820,446	3,137,696	(1,133)	3,136,563
Contributed surplus	h	71,464	4,708	76,172	55,841	6,660	62,501
Deficit	i	(42,296)	(198)	(42,494)	(82,393)	(9,659)	(92,052)
Accumulated other comprehensive loss		-	-	-	(15,031)	-	(15,031)
Total shareholders' equity		3,850,747	3,377	3,854,124	3,096,113	(4,132)	3,091,981
Total liabilities and shareholders' equity		**$ 5,017,631**	**$ 25,634**	**$ 5,043,265**	**$ 4,269,493**	**$ 4,765**	**$ 4,274,258**

iii. Reconciliation of comprehensive income

	Note 4v	CDN GAAP	ADJ	IFRS
		Year ended December 31, 2010		
Petroleum revenue, net of royalties		$ 701,089	$ -	$ 701,089
Power revenue		29,197	-	29,197
		730,286	-	730,286
Diluent and transportation		335,403	-	335,403
Operating expenses		154,568	-	154,568
Depletion and depreciation	e,j,k	124,801	(26,920)	97,881
General and administrative		36,403	-	36,403
Stock-based compensation	h	14,439	(1,953)	12,486
Research and development		5,384	-	5,384
		670,998	(28,873)	642,125
Revenue less operating expenses		59,288	28,873	88,161
Other income (expense)				
Interest income		7,933	-	7,933
Foreign exchange gain, net		49,055	-	49,055
Net finance expense	b,c,e	(66,567)	(16,910)	(83,477)
		(9,579)	(16,910)	(26,489)
Income before income taxes		49,709	11,963	61,672
Deferred income tax expense	f	9,612	2,502	12,114
Net income	l	40,097	9,461	49,558
Other comprehensive income				
Amortization of balance in AOCI, net of taxes		15,031	-	15,031
Comprehensive income for the period	m	$ 55,128	$ 9,461	$ 64,589

iv. Reconciliation of cash flows

	Note 4v	CDN GAAP	ADJ	IFRS
		Year ended December 31, 2010		
Cash provided by (used in):				
Operating activities				
Net income		$ 40,097	$ 9,461	$ 49,558
Adjustments for:				
Depletion and depreciation	e,j,k	124,801	(26,920)	97,881
Stock-based compensation	h	14,439	(1,953)	12,486
Unrealized gain on foreign exchange		(50,741)	-	(50,741)
Unrealized gain on derivative financial liabilities	b	(12,630)	9,341	(3,289)
Deferred income tax expense	f	9,612	2,502	12,114
Other	k	170	6,346	6,516
Net change in non-cash operating working capital items		(50,143)	-	(50,143)
Net cash provided by operating activities		75,605	(1,223)	74,382
Investing activities				
Capital investments	j,k	(484,595)	1,223	(483,372)
Lease inducements		3,501	-	3,501
Change in debt service reserve		102,359	-	102,359
Decrease in restricted cash		12,810	-	12,810
Other		21	-	21
Net change in non-cash investing working capital items		(108,642)	-	(108,642)
Net cash used in investing activities		(474,546)	1,223	(473,323)
Financing activities				
Issue of shares		672,170	-	672,170
Repayment of long-term debt		(10,356)	-	(10,356)
Net cash provided by financing activities		661,814	-	661,814
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		(1,445)	-	(1,445)
Change in cash and cash equivalents		261,428	-	261,428
Cash and cash equivalents, beginning of period		963,018	-	963,018
Cash and cash equivalents, end of period		$ 1,224,446	$ -	$ 1,224,446

v. Explanatory notes:

a) Exploration and evaluation assets and other intangible assets

Under Canadian GAAP, the Corporation applied the full cost method of accounting for oil and gas exploration, development and production activities. Under the full cost method, all costs associated with property acquisition, exploration and development activities are capitalized. Under IFRS, the Corporation expenses all costs incurred in the pre-exploration phase. Costs incurred in the exploration and evaluation phase are capitalized as exploration and evaluation assets. As a result, upon transition to IFRS, the Corporation reclassified $862.7 million in expenditures related to the exploration and evaluation of oil sands leases from property, plant and equipment to exploration and evaluation assets.

Other intangible assets include the cost to maintain the right to participate in a potential pipeline project and investment in software that is not an integral part of the related computer hardware. Expenditures of $24.6 million were reclassified to other intangible assets upon transition to IFRS.

b) Derivative financial liabilities

The Corporation's secured term loan D, which was subsequently replaced with the March 18, 2011 amendment of the senior secured credit facility (see Note 13), carried an interest rate floor of 300 basis points based on US prime and an interest rate floor of 200 basis points based on LIBOR. This interest rate floor was considered an embedded derivative under IFRS as the floor rate exceeded the market rate of interest at the time that the debt was incurred. As a result, the interest rate floor derivative was required to be separated from the carrying value of long-term debt and accounted for as a separate financial liability measured at fair value through income or loss. Upon transition to IFRS, the Corporation recognized the fair value of the financial derivative liability on the balance sheet and reduced the carrying value of long-term debt.

The following is a summary of transitional adjustments to the Corporation's derivative financial liabilities:

	Note 4v	December 31, 2010	January 1, 2010
Derivative financial liabilities as reported under Canadian GAAP		$ -	$ 32,671
IFRS adjustments:			
Derivative financial liabilities – current	b	15,162	14,349
Derivative financial liabilities – non-current	b	22,140	13,613
Derivative financial liabilities as reported under IFRS		37,302	60,633
Less current portion of derivative financial liabilities	b	(15,162)	(47,020)
Non-current portion of derivative financial liabilities		$ 22,140	$ 13,613

c) Deferred debt issue costs

Under Canadian GAAP, the Corporation's debt issue costs incurred to increase the senior secured credit facility in December 2009 were deferred and amortized to interest expense utilizing the effective interest method. Upon transition to IFRS, the Corporation expensed the portion of the debt issue costs associated with amending the senior secured term loans, as under IFRS, it was considered to be an extinguishment of the original financial liability and recognition of a new financial liability. The costs associated with the new revolving credit facility were deferred as a prepaid asset, due to the fact that management had no specific plans to draw down the revolver. These costs are amortized over the life of the revolving credit facility.

d) Non-current portion of long-term debt

The following is a summary of transitional adjustments to the Corporation's non-current portion of long-term debt:

	Note 4v	December 31, 2010	January 1, 2010
Non-current portion of long-term debt as reported under Canadian GAAP		$ 969,933	$ 1,029,687
IFRS adjustments:			
Derivative financial liabilities	b	(26,107)	(30,305)
Debt issue costs expensed on extinguishment of the related financial liability	c	14,173	16,434
Non-current portion of long-term debt as reported under IFRS		$ 957,999	$ 1,015,816

e) Decommissioning provision

Under Canadian GAAP, asset retirement obligations are measured at fair value, incorporating market assumptions and discount rates based on the entity's credit-adjusted risk-free rate. Adjustments are made to asset retirement obligations for changes in the timing or amount of the cash flows and the unwinding of the discount. Changes in estimates that decrease the liability are discounted using the discount rate applied upon initial recognition of the liability while changes that increase the liability are discounted using the current discount rate.

IFRS requires decommissioning provisions to be measured based on management's best estimate of the expenditures that will be made and adjustments to the provision are made in each period for changes in the timing or amount of cash flow, changes in the discount rate, and the accretion of the liability to fair value (unwinding of the discount). Furthermore, the estimated future cash flows are discounted using the discount rate specific to the liability.

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

Under Canadian GAAP, accretion of the discount was included in depletion and depreciation. Under IFRS it is included in net finance expense.

f) Deferred income taxes

The following is a summary of transitional adjustments to the Corporation's deferred income taxes:

	Note 4v	December 31, 2010	January 1, 2010
Deferred income tax liability as reported under Canadian GAAP		$ 22,238	$ 14,290
IFRS adjustments:			
Derivative financial liabilities	b	(2,799)	586
Decommissioning provision	e	1,031	954
Debt issue costs	c	(3,269)	(2,917)
Other	k	(1,072)	-
Depletion and depreciation	j	7,234	-
Deferred income tax liability as reported under IFRS		$ 23,363	$ 12,913

g) Share capital

Under Canadian GAAP, the impact of future income taxes related to share issue costs are recognized directly in shareholders' equity. Any subsequent period changes affecting the future 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 shareholders' equity. However, unlike Canadian GAAP, subsequent changes to the deferred tax expense recognized in respect of share issue costs are also recognized in shareholders' equity.

h) Share-based payments

Under Canadian GAAP, the Corporation recognized an expense related to share-based payments on a straight-line basis through the date of full vesting and did not incorporate a forfeiture multiple. Under IFRS, the Corporation is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate.

i) Deficit

The following is a summary of transitional adjustments to the Corporation's deficit:

	Note 4v	December 31, 2010	January 1, 2010
Deficit as reported under Canadian GAAP		$ (42,296)	$ (82,393)
IFRS adjustments:			
Derivative financial liabilities	b	(8,396)	1,757
Decommissioning provision	e	3,093	2,862
Share capital	g	1,133	1,133
Share-based payments	h	(4,709)	(6,660)
Debt issue costs	c	(9,806)	(8,751)
Other	k	(3,215)	-
Depletion and depreciation	j	21,702	-
Deficit as reported under IFRS		$ (42,494)	$ (92,052)

j) Depletion and depreciation

Upon transition to IFRS, the Corporation adopted a policy of depleting oil sands and natural gas interests on a unit of production basis over estimated proved reserves while major facilities and equipment are depreciated on a unit of production basis over the total productive capacity of the facilities and equipment. Pipeline assets are depreciated on a straight-line basis over the remaining useful life of the pipeline. The depletion and depreciation policy under Canadian GAAP was based on the full cost method of accounting whereby all of the Corporation's oil sands properties and equipment were depleted on a unit of production basis over proved reserves.

k) Other

IFRS does not prescribe specific oil and gas accounting guidance other than costs associated with the exploration and evaluation phase. In 2010, the Corporation allowed certain interests in petroleum and natural gas leases to expire. Under Canadian GAAP full cost accounting, these leases were not removed from property, plant and equipment as these dispositions did not result in a change to the depletion rate of 20% or more. Under IFRS, all gains or losses on dispositions of property, plant and equipment are recognized in the statement of comprehensive income. This resulted in an increase to depletion and depreciation expense of $3.1 million for the year ended December 31, 2010.

IFRS requires that capitalized borrowing costs be recorded net of investment income earned on the temporary investment of the borrowed funds. This resulted in a decrease to interest capitalized of $1.2 million for the year ended December 31, 2010.

l) Net income

The following is a summary of transitional adjustments to the Corporation's net income:

	Note 4v	December 31, 2010
Net income as reported under Canadian GAAP		$ 40,097
IFRS adjustments:		
Derivative financial liabilities	b	(10,154)
Decommissioning provision	e	230
Share-based payments	h	1,952
Debt issue costs	c	(1,055)
Other	k	(3,213)
Depletion and depreciation	j	21,701
Net income as reported under IFRS		$ 49,558

m) Net income

The following is a summary of transitional adjustments to the Corporation's comprehensive income:

	Note 4v	December 31, 2010
Comprehensive income as reported under Canadian GAAP		$ 55,128
IFRS adjustments:		
Difference in net income, net of tax		9,461
Comprehensive income as reported under IFRS		$ 64,589

5. DETERMINATION OF FAIR VALUE

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

i. Cash and cash equivalents, short-term investments, trade receivables, debt service reserve, restricted cash, trade payables and deferred lease inducements:

The fair values of cash and cash equivalents, short-term investments, trade receivables, debt service reserve, restricted cash and trade payables are estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2011 and 2010 and January 1, 2010, the carrying value approximates the fair value of the respective assets and liabilities due to the short term nature of the instruments.

ii. Other assets:

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

iii. Derivative financial liabilities and long-term debt:

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

iv. Share-based payments:

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

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

6. FINANCIAL INSTRUMENTS AND DERIVATIVE FINANCIAL LIABILITIES

The financial instruments recognized on the balance sheet are comprised of cash and cash equivalents, short-term investments, trade receivables, other assets, debt service reserve, restricted cash, trade payables, derivative financial liabilities and long-term debt. As at December 31, 2011, short-term investments, other assets, debt service reserve, restricted cash and derivative financial liabilities were classified as held-for-trading financial instruments; cash and cash equivalents and trade receivables were classified as loans and receivables; and trade payables and deferred lease inducements were classified as other financial liabilities. Long-term debt was carried at amortized cost.

(a) Fair value measurement

The carrying value of cash and cash equivalents, short-term investments, trade receivables, debt service reserve, restricted cash and trade payables included on 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 of long-term debt is derived from quoted prices from financial institutions. At December 31, 2011 the fair value of long-term debt is $1,789.9 million (December 31, 2010 - $934.4 million, January 1, 2010 - $921.2 million).

The fair value measurement information for other assets and derivative financial liabilities is noted below.

			Fair value measurements using		
December 31, 2011	**Carrying amount**	**Fair value**	**prices in active markets (Level 1)**	**Quoted other observable inputs (Level 2)**	**Significant Significant unobservable inputs (Level 3)**
Financial assets					
Other assets	**$ 7,554**	**$ 7,554**	**$ -**	**$ -**	**$ 7,554**
Financial liabilities					
Derivative financial liabilities	**24,326**	**24,326**	**-**	**24,326**	**-**

			Fair value measurements using		
December 31, 2010	Carrying amount	Fair value	prices in active markets (Level 1)	Quoted other observable inputs (Level 2)	Significant Significant unobservable inputs (Level 3)
Financial assets					
Other assets	$ 7,492	$ 7,492	$ -	$ -	$ 7,492
Financial liabilities					
Derivative financial liabilities	37,302	37,302	-	37,302	-

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

As at December 31, 2011 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.

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

Level 3 fair value measurements are based on unobservable information.

Other assets – Other assets are comprised of investments in asset-backed commercial paper that were 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.

(b) Interest rate risk

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

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. As noted below, in order to mitigate a portion of this risk, the Corporation entered into interest rate swap contracts, effective September 30 and December 31, 2011, to fix the interest rate on US$300 million and US$150 million, respectively, of the US$1,000 million senior secured term loan. At December 31, 2011, there was an unrealized loss on the interest rate swaps of $2.5 million (December 31, 2010 – nil).

Amount	Remaining term	Fixed rate	Floating rate
US$300 million	Jan 2012-Sept 2016	4.686%	3 month LIBOR(1)
US$150 million	Jan 2012-Sept 2016	4.626%	3 month LIBOR(1)

(1) London Interbank Offered Rate

As at December 31, 2011, a 100 basis points increase/decrease in LIBOR, excluding the impact of interest capitalized, interest rate swaps and the interest rate floor, would have resulted in a $10.1 million decrease/increase in net income before income taxes (December 31, 2010 - $9.9 million).

(c) Foreign currency risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the fair value or future cash flows of the Corporation's financial assets or liabilities. The Corporation previously had a US dollar denominated debt service reserve account and has US dollar denominated long-term debt as described in notes 8 and 15 respectively. As at December 31, 2011, a US$0.01 change in the US dollar relative to the Canadian dollar exchange rate would have resulted in a corresponding change in the carrying value of long-term debt of US$17.5 million (December 31, 2010 - US$10.0 million).

(d) Commodity price risk

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

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

(e) Credit risk

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty to a financial instrument fails to meet its obligations in accordance with agreed terms. This credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. Agreements are entered into with major financial institutions with investment grade credit ratings. A substantial portion of accounts receivable are with customers in the petroleum and natural gas industry and are subject to normal industry credit risk. At December 31, 2011, the Corporation's estimated maximum exposure to credit risk related to customers was $130.7 million. There were no significant amounts which were greater than 90 days as at December 31, 2011.

The Corporation's cash balances are used to fund the development of its oil sands properties. As a result, the primary objectives of the investment portfolio are low risk capital preservation and high liquidity. The cash balances are invested in high grade liquid short term debt such as commercial, government and bank paper. The cash, cash equivalents and short-term investments balance at December 31, 2011 was $1,647.1 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 $1,647.1 million.

The Corporation's investments in MAV Notes and US Auction Rate Securities ("ARS") 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. The Corporation's estimated maximum exposure to credit risk related to its investments in MAV Notes and US Auction Rate Securities is $7.6 million.

(f) Liquidity risk

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

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

As at December 31, 2010	Total	< 1 year	1 – 3 years	4 – 5 years	More than 5 years
Long-term debt	$ 994,015	$ 10,065	$ 60,014	$ 19,296	$ 904,640
Interest on long-term debt	295,083	57,890	111,590	111,590	14,013
Trade payables	144,378	144,378	-	-	-
	$ 1,433,476	$ 212,333	$ 171,604	$ 130,886	$ 918,653

7. TRADE RECEIVABLES AND OTHER

	December 31, 2011	December 31, 2010	January 1, 2010
Trade receivables	**$ 130,669**	$ 94,170	$ 28,524
Deposits and advances	**3,706**	2,794	5,138
Current portion of prepaid financing costs	**1,170**	603	762
	$ 135,545	$ 97,567	$ 34,424

8. INVENTORIES

	December 31, 2011	December 31, 2010	January 1, 2010
Diluent	**$ 7,078**	$ 5,600	$ 4,388
Bitumen blend	**1,107**	573	1,172
Materials and supplies	**1,022**	-	-
	$ 9,207	$ 6,173	$ 5,560

During the year ended December 31, 2011 a total of $451.0 million (2010 - $322.9 million) in inventory product costs were charged to earnings through diluent and transportation.

9. DEBT SERVICE RESERVE

On December 23, 2009, as part of the modifications to the Corporation's senior secured credit facilities, the Corporation placed US$97.8 million in a debt service reserve to fund principal and interest payments through December 31, 2010. Investments were held in a US dollar debt service account and were comprised of high grade liquid short-term debt such as commercial, government, and bank paper. As of December 31, 2010 the Corporation was no longer required to maintain a debt service reserve account.

The US dollar denominated debt service reserve account was translated into Canadian dollars at the period end exchange rate. The foreign exchange loss on the restricted investments has been recognized in net finance expense.

10. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Corporate assets	Total
Cost			
Balance as at January 1, 2010	$ 2,258,251	$ 3,156	$ 2,261,407
Additions	389,431	13,712	403,143
Balance as at December 31, 2010	$ 2,647,682	$ 16,868	$ 2,664,550
Additions	915,615	10,742	926,357
Disposals	(5,540)	-	(5,540)
Balance as at December 31, 2011	**$ 3,557,757**	**$ 27,610**	**$ 3,585,367**
Accumulated depletion and depreciation			
Balance as at January 1, 2010	$ 3,271	$ 1,111	$ 4,382
Depletion and depreciation for the period	93,635	59	93,694
Balance as at December 31, 2010	$ 96,906	$ 1,170	$ 98,076
Depletion and depreciation for the period	121,861	2,151	124,012
Disposals	(5,540)	-	(5,540)
Balance as at December 31, 2011	**$ 213,227**	**$ 3,321**	**$ 216,548**
Carrying Amounts			
As at January 1, 2010	$ 2,254,980	$ 2,045	$ 2,257,025
As at December 31, 2010	$ 2,550,776	$ 15,698	$ 2,566,474
As at December 31, 2011	**$ 3,344,530**	**$ 24,289**	**$ 3,368,819**

During the year ended December 31, 2011 the Corporation capitalized $14.1 million (year ended December 31, 2010 - $11.3 million) of general and administrative expenses and $5.1 million (year ended December 31, 2010 - $3.7 million) of stock-based compensation costs relating to oil sands exploration and development activities. In addition, $14.6 million of interest and finance charges related to the development of growth capital projects, including Phase 2B and Phase 3, were capitalized during the year ended December 31, 2011 utilizing a weighted average capitalization rate of 4.6% (year ended December 31, 2010 - $17.4 million and weighted average capitalization rate – 6.0%).

The Corporation transports its bitumen blend volumes and diluents purchases on pipelines that are operated by Access Pipeline. The Corporation has a 50% interest in this jointly controlled entity and accounts for its investment using the proportionate consolidation method. As at December 31, 2011, the Corporation's proportionate interest in the joint venture's related pipeline assets was $405.5 million, which have been included as crude oil assets in Property, Plant and Equipment (December 31, 2010 - $355.5 million).

Operating commitments of $1.7 million related to the joint venture are included in "Other commitments" presented within Note 26.

11. EXPLORATION AND EVALUATION ASSETS

Cost	
Balance as at January 1, 2010	$ 862,703
Additions	75,283
Balance as at December 31, 2010	$ 937,986
Additions	53,819
Balance as at December 31, 2011	**$ 991,805**

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. These assets are not subject to depletion, as they are in the exploration and evaluation stage, but are reviewed on a quarterly basis for impairment. As of December 31, 2011, no impairment has been recognized on these assets.

12. OTHER INTANGIBLE ASSETS

Cost	
Balance as at January 1, 2010	$ 24,990
Additions	8,748
Balance as at December 31, 2010	$ 33,738
Additions	4,448
Balance as at December 31, 2011	**$ 38,186**

Accumulated depreciation	
Balance as at January 1, 2010	$ 377
Depreciation	203
Balance as at December 31, 2010	$ 580
Depreciation	314
Balance as at December 31, 2011	**$ 894**

Carrying Amounts	
As at January 1, 2010	$ 24,613
As at December 31, 2010	$ 33,158
As at December 31, 2011	**$ 37,292**

Other assets include the cost to maintain the right to participate in a potential pipeline project and in the cost of software that is not an integral part of the related computer hardware. As at December 31, 2011, the potential pipeline project has not been amortized.

13. 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 revolving credit facility.

14. OTHER ASSETS

	December 31, 2011	December 31, 2010	January 1, 2010
MAV Notes (formerly asset-backed commercial paper) [a]	**$ 4,707**	$ 4,707	$ 4,769
US Auction Rate Securities [b]	**2,847**	2,785	2,974
Prepaid financing costs [c]	**4,928**	3,166	4,765
	12,482	10,658	12,508
Less current portion of prepaid financing costs	**(1,170)**	(603)	(762)
	$ 11,312	$ 10,055	$ 11,746

(a) The Corporation's investment of $12.3 million in Canadian non-bank asset-backed commercial paper was restructured in 2009 into floating rate Master Asset Vehicle ("MAV") notes that mature between 2013 and 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 comprehensive income in the period in which they arise. As at December 31, 2011, the total impairment provision on the notes was $7.6 million (2010 - $7.6 million).

(b) US$3.2 million investment in US Auction Rate Securities (ARS) is considered an illiquid asset and is recorded at its fair value based on a discounted cash flow valuation using observable information regarding the timing of payments and credit rating of the securities.

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

15. TRADE PAYABLES

	December 31, 2011	December 31, 2010	January 1, 2010
Trade payables	**$ 21,225**	$ 4,395	$ 1,177
Accruals	**217,704**	105,370	43,779
Other payables	**48,023**	34,288	26,631
Interest payable	**14,674**	325	255
	$ 301,626	$ 144,378	$ 71,842

16. LONG-TERM DEBT

	December 31, 2011	December 31, 2010	January 1, 2010
Senior secured term loan (December 31, 2011 - US$997.5 million; December 31, 2010 - US$999.4 million; January 1, 2010 – US$1,009.5 million)[a]	**$ 1,014,458**	$ 994,015	$ 1,056,577
Senior unsecured notes (US$750.0 million)[b]	**762,750**	-	-
	1,777,208	994,015	1,056,577
Less current portion of senior secured term loan	**(10,145)**	(10,065)	(10,593)
Less unamortized financial derivative liability discount	**(12,130)**	(25,951)	(30,168)
Less unamortized deferred debt issue costs	**(13,539)**	-	-
	$ 1,741,394	$ 957,999	$ 1,015,816

The US dollar denominated debt is translated into Canadian dollars at the period end exchange rate of US$1 = C$1.017 (December 31, 2010 – US$1 = C$0.9946; January 1, 2010 – US$1 = C$1.0466).

(a) Effective March 18, 2011, the Corporation agreed to amend, extend and increase its senior secured credit facility. Under IFRS, this was considered to be an extinguishment of the original financial liability and the recognition of a new financial liability. The senior secured credit facilities are comprised of a US$1.0 billion term loan and a five year US$500.0 million revolving credit facility. As part of the agreement, the Corporation extended the maturity date on US$999.4 million in existing debt to March 18, 2018 and increased its borrowing under the senior secured credit facility by US$0.6 million. In addition, the Corporation reduced the interest rate on the term loan from the London Interbank Offered Rate ("LIBOR") plus 400 basis points to LIBOR plus 300 basis points and reduced the LIBOR floor rate from 200 basis points to 100 basis points. Principal repayments on the term loan of 1% per annum are paid quarterly and the first principal payment was made on December 31, 2011. Interest is paid quarterly. All of the Corporation's assets, except for its interest in the Access Pipeline and certain undeveloped properties, have been pledged as collateral on the senior secured term loan.

As at December 31, 2011, $0.8 million (December 31, 2010 - $8.3 million) of the revolving credit facility was utilized to support letters of credit. As at December 31, 2011, no amount had been drawn under the revolving credit facility.

(b) Effective March 18, 2011, the Corporation issued US$750 million in aggregate principal amount of 6.5% Senior Unsecured Notes with a maturity date of March 15, 2021. Interest is paid semi-annually. No principal payments are required until March 15, 2021. The Corporation has deferred debt issue costs of $13.5 million and will amortize these costs over the life of the notes utilizing the effective interest method.

	2012	2013	2014	2015	2016	Thereafter
Required debt principal repayments	$10,145	$10,145	$10,145	$10,145	$10,145	$1,726,483

17. OTHER LIABILITIES

	December 31, 2011	December 31, 2010	January 1, 2010
Derivative financial liabilities[a]	**$ 24,326**	$ 37,302	$ 60,633
Decommissioning provision[b]	**65,360**	12,557	10,480
Deferred lease inducements[c]	**6,125**	3,477	-
Other liabilities	**95,811**	53,336	71,113
Less current portion of derivative financial liabilities	**(4,056)**	(15,162)	(47,020)
Less current portion of deferred lease inducements	**(749)**	(292)	-
Non-current portion of other liabilities	**$ 91,006**	$ 37,882	$ 24,093

(a) Derivative financial liability

The Corporation's term loan D, which was subsequently replaced with the March 18, 2011 amendment of the senior secured credit facility (see Note 12), carried an interest rate floor of 300 basis points based on US prime and an interest rate floor of 200 basis points based on LIBOR. This interest rate floor was considered an embedded derivative under IFRS as the floor rate exceeded the market rate of interest at the time that the debt was incurred. As a result, the interest rate floor derivative was required to be separated from the carrying value of long-term debt and accounted for as a separate financial liability measured at fair value through income or loss.

On March 18, 2011 the senior secured credit facility was amended, which required the $37.2 million fair value of the 2% floor derivative financial liability to be derecognized through gain on debt modification. The amended senior secured credit facility carries an interest rate floor of 200 basis points based on US prime and an interest rate floor of 100 basis points based on LIBOR. This interest rate floor is considered an embedded derivative as the floor rate exceeded the market rate of interest at the time that the debt was incurred. As a result, the interest rate floor derivative is required to be separated from the carrying value of long-term debt and accounted for as a separate financial liability measured at fair value through income or loss.

The Corporation is exposed to interest rate risk in relation to interest income earned on cash and cash equivalents, short-term investments and interest expense on floating rate long-term debt. To mitigate a portion of the risk of interest rate increases on long-term debt, the Corporation periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. Effective September 30 and December 31, 2011, the Corporation entered into interest rate swaps for nominal amounts of US$300.0 million and US$150 million, respectively (note 6(b)). These interest rate swap contracts expire on September 30, 2016. The Corporation's previous interest rate swap contracts expired December 31, 2010. Interest rate swaps are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

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

	2011	2010
Derivative financial liability, beginning of period		
Embedded derivative	$ 37,302	$ 27,962
Interest rate swaps	-	32,671
	37,302	60,633
Decrease in interest swap liability fair value	-	(32,671)
Change in fair value of embedded derivative – 2% interest floor	-	9,340
Write-off of embedded derivative – 2% interest floor on debt amendment	(37,302)	-
Embedded derivative recognized on 1% interest floor	13,507	-
Increase in fair value of embedded derivative on 1% interest floor	8,346	-
Increase in interest swap liability fair value	2,473	-
Derivative financial liabilities, end of period	24,326	37,302
Less current portion of derivative financial liabilities	(4,056)	(15,162)
Non-current portion of derivative financial liabilities	$ 20,270	$ 22,140

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

	2011	2010
Decommissioning provision, beginning of period	$ 12,557	$ 10,480
Changes in estimated future cash flows	24,876	-
Liabilities acquired during the period	1,522	-
Liabilities incurred during the period	25,471	1,634
Liabilities settled during the period	(712)	(299)
Accretion for the period	1,646	742
Decommissioning provision, end of period	$ 65,360	$ 12,557

The total decommissioning provision is based on the estimated costs to reclaim and abandon the Corporation's crude oil properties and the estimated timing of the costs to be incurred in future years. The Corporation has estimated the net present value of the decommissioning obligations to be $65.4 million as at December 31, 2011 (December 31, 2010 - $12.6 million) based on an obligation of $179.1 million (December 31, 2010 - $37.3 million) and a discount factor of 5.4% (December 31, 2010 – 6.8%). This obligation is estimated to be settled in periods up to 2057.

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

18. DEFERRED TAXES

The deferred tax provisions differ from results which would be obtained had the Corporation applied the combined federal and provincial statutory rates of 26.5% (2010 – 28.0%) to earnings. The reasons for these differences are as follows:

	2011	2010
Expected income tax expense	$ 29,066	$ 17,268
Add (deduct) the effect of:		
Stock-based compensation	5,659	3,496
Non-taxable loss (gain) on foreign exchange	6,197	(7,306)
Taxable capital losses not recognized	7,548	-
Other	(2,623)	(1,344)
	$ 45,847	$ 12,114

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

	2011	2010
Deferred tax liabilities:		
Deferred tax liabilities to be recovered after more than 12 months	$ 452,769	$ 396,562
Deferred tax liabilities to be recovered within 12 months	25,427	45,115
	478,196	441,677
Deferred tax assets:		
Deferred tax assets to be recovered after more than 12 months	(393,619)	(425,932)
Deferred tax assets to be recovered within 12 months	(16,608)	7,618
	(410,227)	(418,314)
Deferred tax liabilities (net)	$ 67,969	$ 23,363

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

	2011	2010
At January 1	$ 23,363	$ 12,913
Income statement charge	45,847	12,114
Tax charge/(credit) relating to components of other comprehensive income	-	5,010
Other	(1,241)	2,500
Tax charged/(credited) directly to equity	-	(9,174)
At December 31	$ 67,969	$ 23,363

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

Deferred tax liabilities	Accelerated tax depreciation	Provisions	Other	Total
At January 1, 2010	$ 369,691	$ -	$ 344	$ 370,035
Charged/(credited) to the income statement	62,649	-	6,493	69,142
Other	2,500	-	-	2,500
At December 31, 2010	434,840	-	6,837	441,677
Charged/(credited) to the income statement	43,701	240	(6,181)	37,760
Other	(1,241)	-	-	(1,241)
At December 31, 2011	**$ 477,300**	**$ 240**	**$ 656**	**$ 478,196**

Deferred tax assets	Tax losses	Derivative financial liabilities	Other	Total
At January 1, 2010	$ (330,793)	$ (7,582)	$ (18,747)	$ (357,122)
Charged/(credited) to the income statement	(65,898)	(6,754)	15,624	(57,028)
Charged/(credited) to the other comprehensive income	-	5,010	-	5,010
Charged/(credited) to equity	-	-	(9,174)	(9,174)
At December 31, 2010	(396,691)	(9,326)	(12,297)	(418,314)
Charged/(credited) to the income statement	1,636	3,245	3,206	8,087
At December 31, 2011	**$ (395,055)**	**$ (6,081)**	**$ (9,091)**	**$ (410,227)**

At December 31, 2011, the Corporation had approximately $3,114.7 million in available tax pools (December 31, 2010 - $3,145.5 million; January 1, 2010 - $2,911.4 million). Included in the tax pools are $1,580.2 million of non-capital loss carry forward balances ($211.6 million expiring in 2026; $253.9 million expiring in 2027; $341.4 million expiring in 2028; $528.7 million expiring in 2029; and $244.6 million expiring in 2030). In addition, at December 31, 2011, the Corporation had an additional $887.8 million (December 31, 2010 - $247.2 million; January 1, 2010 - $88.9 million) of capital investment in incomplete projects which will serve to increase available tax pools upon completion of the projects.

19. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

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

	2011		2010	
	Number of shares	Amount	Number of shares	Amount
Balance, beginning of period	**189,875,151**	**$ 3,820,446**	169,130,053	$ 3,136,563
Issued upon exercise of stock options	**3,462,840**	**52,037**	745,098	11,406
Issued upon vesting and release of RSUs	**133,714**	**4,710**	-	-
Issued for cash	**-**	**-**	20,000,000	700,000
Share issue costs, net of taxes (2010 – $9,174)	**-**	**-**	-	(27,523)
Balance, end of period	**193,471,705**	**$ 3,877,193**	189,875,151	$ 3,820,446

(c) Share based payments:

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 19,347,171 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").

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 with an expiry date earlier than January 1, 2013. The new expiry date for all such outstanding options is January 31, 2013.

	2011			2010		
	Stock options		**Weighted average exercise price per share**	**Stock options**		**Weighted average exercise price per share**
Outstanding, beginning of period	**12,919,846**	**$**	**21.51**	12,609,407	$	19.89
Granted	**810,682**		**50.52**	1,208,170		33.48
Exercised	**(3,462,840)**		**11.47**	(745,098)		11.90
Forfeited	**(77,585)**		**37.41**	(152,633)		29.35
Outstanding, end of period	**10,190,103**	**$**	**27.12**	12,919,846	$	21.51

	Outstanding			Vested		
Range of exercise prices	Options	Weighted average exercise price	Weighted average remaining life (in years)	Options	Weighted average exercise price	Weighted average remaining life (in years)
$1.00 - $11.00	3,013,832	$7.18	1.09	3,013,832	$7.18	1.09
$11.01 - $24.00	1,800,865	24.00	4.56	1,253,615	24.00	4.55
$24.01 - $33.50	764,100	27.82	1.72	764,100	27.82	1.72
$33.51 - $41.00	3,846,808	39.34	3.64	3,162,701	40.34	3.19
$41.01 - $51.43	764,498	50.85	6.42	-	-	-
	10,190,103	$27.12	3.11	8,194,248	$24.48	2.49

The fair value of each option granted during the year ended December 31, 2011 and 2010 is estimated on the date of the grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

		2011		2010
Risk free rate		**2.19%**		2.34%
Expected lives		**5 years**		5 years
Volatility		**40%**		36%
Annual dividend per share	**$**	**nil**	$	nil
Fair value of options granted	**$**	**19.26**	$	12.27

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.

	2011	2010
	RSUs	RSUs
Outstanding, beginning of period	**404,945**	-
Granted	**301,273**	407,610
Vested and released	**(133,714)**	-
Forfeited	**(18,142)**	(2,665)
Outstanding, end of period	**554,362**	404,945

(d) Contributed Surplus:

		2011		2010
Balance, beginning of period	**$**	**76,172**	$	62,501
Stock-based compensation - expensed		**21,356**		12,486
Stock-based compensation - capitalized		**5,070**		3,724
Stock options exercised		**(17,030)**		(2,539)
Balance, end of period	**$**	**85,568**	$	76,172

20. PETROLEUM REVENUE

		2011		2010
Petroleum sales	**$**	**1,021,036**	$	717,610
Royalties		**(31,438)**		(16,521)
Petroleum revenue	**$**	**989,598**	$	701,089

21. NET FINANCE EXPENSE

		2011		2010
Total interest expense	**$**	**88,276**	$	69,021
Less capitalized interest		**(14,629)**		(17,409)
Net interest expense		**73,647**		51,612
Accretion on decommissioning provision		**1,646**		742
Fair value loss on embedded derivative liabilities		**8,346**		9,341
Unrealized fair value loss (gain) on interest rate swaps		**2,473**		(32,671)
Realized loss on interest rate swaps		**532**		34,412
Amortization of unrealized loss from accumulated other comprehensive income		**-**		20,041
Net finance expense	**$**	**86,644**	$	83,477

22. WAGES AND EMPLOYEE BENEFITS EXPENSE

		2011		2010
Operating expense:				
Salaries and wages	**$**	**27,804**	$	18,953
Short-term employee benefits		**2,096**		1,422
General and administrative expense:				
Salaries and wages		**39,891**		30,481
Short-term employee benefits		**4,381**		3,209
	$	**74,172**	$	54,065

23. COMPENSATION OF KEY MANAGEMENT PERSONNEL

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

		2011		2010
Salaries and short-term employee benefits	**$**	**7,254**	$	6,624
Share-based compensation expense		**8,015**		4,072
	$	**15,269**	$	10,696

24. SUPPLEMENTAL CASH FLOW DISCLOSURES

		2011		2010
Cash provided by (used in):				
Change in non-cash working capital items:				
Short-term investments	**$**	**15,468**	$	(167,406)
Trade receivables and other		**(37,411)**		(63,302)
Inventories		**(3,034)**		(613)
Trade payables		**157,248**		72,536
	$	**132,271**	$	(158,785)
Changes in non-cash working capital relating to:				
Operations	**$**	**18,098**	$	(50,143)
Investing		**114,173**		(108,642)
	$	**132,271**	$	(158,785)
Cash and cash equivalents:				
Cash	**$**	**29,519**	$	18,857
Cash equivalents		**1,465,612**		1,205,589
	$	**1,495,131**	$	1,224,446

25. EARNINGS PER COMMON SHARE

		2011		2010
Net income	**$**	**63,837**	$	49,558
Weighted average common shares outstanding		**192,298,562**		177,476,449
Dilutive effect of stock options and restricted share units		**5,475,942**		5,893,225
Weighted average common shares outstanding – diluted		**197,774,504**		183,369,674
Earnings per share, basic	**$**	**0.33**	$	0.28
Earnings per share, diluted	**$**	**0.32**	$	0.27

26. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at December 31, 2011.

Operating:

	2012	2013	2014	2015	2016	Thereafter
Office lease rentals	$ 8,121	$ 9,370	$ 9,370	$ 9,545	$ 9,936	$ 68,657
Diluent purchases	222,006	22,012	-	-	-	-
Pipeline transportation	-	-	31,088	31,088	62,347	1,306,736
Other commitments	3,269	4,763	1,685	440	-	-
Annual commitments	$ 233,396	$ 36,145	$ 42,143	$ 41,073	$ 72,283	$ 1,375,393

Capital:

As part of normal operations, the Corporation has entered into a total of $370.8 million in capital commitments to be made in periods through 2016.

(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.

27. CAPITAL DISCLOSURES

The Corporation considers capital at December 31, 2011 to include long term debt of $1,751.5 million (December 31, 2010 – $958.0 million; January 1, 2010 - $1,015.8 million) and share capital of $3,877.2 million (December 31, 2010 - $3,820.5 million; January 1, 2010 - $3,136.6 million).

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.
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.

28. COMPARATIVE FIGURES

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

Information for Shareholders

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

Transfer Agent
Olympia Trust Company
Toll Free: (800) 727-4493
Email: cssinquiries@olympiatrust.com
Website: www.olympiatrust.com

Auditor
PricewaterhouseCoopers LLP

Independent Reserve Evaluator
GLJ Petroleum Consultants

Annual General Meeting
May 3, 2012
Bow Glacier Room, Centennial Place
Third Floor West, 250 5 Street SW
Calgary, Alberta

Head Office
11th Floor, 520 – 3 Avenue SW
Calgary, Alberta, Canada
T2P 0R3
Tel: 403-770-0446
Fax: 403-264-1711
info@megenergy.com

Analyst and Investor Inquiries
Helen Kelly
Director, Investor Relations
Tel: 403-767-6206
invest@megenergy.com

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

Directors and Officers

Board of Directors

A. Boyd Anderson (1)(2)
(Lead Director, independent)

Harvey Doerr (2)
(independent)

Robert B. Hodgins (1)(3)
(independent)

Peter R. Kagan (2)(3)
(independent)

David B. Krieger (1)
(independent)

Honourable E. Peter Lougheed
(independent)

William J. (Bill) McCaffrey
(Chairman, non-independent, management)

James D. McFarland (2)(3)
(independent)

David J. Wizinsky
(non-independent, management)

Li Zheng
(independent)

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

(1) Audit Committee
(2) Governance and Nominating Committee
(3) Compensation Committee

Corporate Officers

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

Dale Hohm
Chief Financial Officer

Grant Boyd
Senior Vice President, Resource Management – Growth Properties

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

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