PRESS RELEASE

# CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES
# 2011 FIRST QUARTER RESULTS
## CALGARY, ALBERTA – MAY 5, 2011 – FOR IMMEDIATE RELEASE

Commenting on first quarter results, Canadian Natural's Chairman, Allan Markin stated, "Our primary heavy crude oil assets delivered record quarterly production supported by the expanded drilling program we continue to execute. Our teams continue to focus on safe, efficient and effective operations, especially during this year's challenging Western Canadian winter weather conditions. This is demonstrated in per unit production expense for our North America Exploration and Production crude oil and NGLs which was 6% lower than the same quarter last year."

John Langille, Vice-Chairman of Canadian Natural continued, "We exited the quarter in a solid financial position on the back of strong production and cash flow from our operations. The size and breadth of our operations resulted in no material change in debt position despite the curtailment of sales at Horizon during the quarter due to the coker fire. Our debt to book capital remained favorable at 29% at the end of the first quarter. We expect a solid year of cash flow generation and prudent capital reinvestment in 2011 which will contribute to the ongoing strength of the Company's financial position."

Steve Laut, President of Canadian Natural stated, "Our project portfolio is strong and we continue to develop our short, mid and long term projects. In 2011, we target to execute a record drilling program in primary heavy crude oil which provides strong financial returns. In addition, we continue to implement strategies at Pelican Lake to increase production levels from this world class oil pool. At Kirby, construction of the 40,000 barrel per day targeted peak production facility is underway as we continue to develop our vast thermal asset base. At Horizon, we have mitigated some of the impact of the fire through the acceleration of portions of the turnaround originally scheduled for 2012. As a result of this activity we believe that we will be able to defer remaining portions of that turnaround to 2013. Additionally, the construction of the third Ore Preparation Plant looks to be slightly ahead of schedule, which will translate into higher reliability levels upon recommencement of operations."

## QUARTERLY HIGHLIGHTS

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions, except as noted) | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010(1) |
| Net earnings (loss) | **$ 46** | $ (309) | $ 735 |
| Per common share - basic | **$ 0.04** | $ (0.28) | $ 0.68 |
| - diluted | **$ 0.04** | $ (0.28) | $ 0.67 |
| Adjusted net earnings from operations (2) | **$ 228** | $ 585 | $ 639 |
| Per common share - basic | **$ 0.21** | $ 0.54 | $ 0.59 |
| - diluted | **$ 0.21** | $ 0.53 | $ 0.58 |
| Cash flow from operations (3) | **$ 1,074** | $ 1,652 | $ 1,507 |
| Per common share - basic | **$ 0.98** | $ 1.52 | $ 1.39 |
| - diluted | **$ 0.97** | $ 1.50 | $ 1.38 |
| Capital expenditures, net of dispositions | **$ 1,694** | $ 1,945 | $ 1,076 |
| Daily production, before royalties | | | |
| Natural gas (MMcf/d) | **1,256** | 1,252 | 1,226 |
| Crude oil and NGLs (bbl/d) | **356,988** | 438,835 | 406,266 |
| Equivalent production (BOE/d) | **566,231** | 647,441 | 610,556 |

*(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.*

*(2) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in Management's Discussion and Analysis ("MD&A").*

*(3) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and debt repayment. The derivation of this measure is discussed in the MD&A.*

- The Company's large, diverse asset base continues to deliver significant value to shareholders. In Q1/11 all production guidance targets were met other than for Horizon which missed original production targets due to the coker fire. The Company's North America Exploration and Production assets delivered significant cash flow of approximately $990 million in the quarter. Similarly, International operations generated approximately $260 million of cash flow in the quarter. Horizon cash flow was severely impacted due to the early January coker fire. Horizon segment revenue dropped by approximately $595 million from Q4/10 levels while operating costs, which are predominantly fixed in nature, only decreased by approximately $48 million from Q4/10.
- Total crude oil and NGLs production for Q1/11 was 356,988 bbl/d. Q1/11 crude oil production volumes decreased 12% from Q1/10 of 406,266 bbl/d and 19% from Q4/10 of 438,835 bbl/d primarily due to the suspension of Horizon Oil Sands ("Horizon") production following the fire in the Company's primary upgrading plant in early January 2011.
- Crude oil and NGLs production in North America Exploration and Production in Q1/11 was 290,130 bbl/d. Q1/11 crude oil and NGLs production volumes increased 15% from Q1/10 levels of 252,450 bbl/d, and increased 1% from Q4/10 levels of 286,698 bbl/d. The increase in volumes in Q1/11 from Q1/10 was due to increases in all areas of crude oil and NGLs production in North America Exploration and Production and in particular the Company's thermal operations. The increase in Q1/11 from Q4/10 was due to increases in light and medium crude oil and NGLs, Pelican Lake heavy crude oil and primary heavy crude oil offset by a decrease in bitumen (thermal oil) volumes as a result of the timing of steaming cycles.
- Natural gas production volumes for Q1/11 represented 37% of the Company's total production volumes. Natural gas production for Q1/11 averaged 1,256 MMcf/d, a 2% increase from Q1/10 of 1,226 MMcf/d and comparable to Q4/10 production of 1,252 MMcf/d. The increase in natural gas production from Q1/10 reflects new production volumes from the Septimus facility in Northeast British Columbia and from natural gas producing properties acquired during 2010.

- Quarterly cash flow from operations was $1.07 billion compared to $1.51 billion for Q1/10 and $1.65 billion for Q4/10. The decrease in cash flow from Q1/10 and Q4/10 is primarily related to lower synthetic crude oil ("SCO") sales revenues and continuation of operating costs as a result of the suspension of production from Horizon following the fire in the Company's primary upgrading plant in early January 2011.

- Quarterly net earnings in Q1/11 of $46 million included net unrealized after-tax expenses of $182 million comprised of the $104 million impact of the revised United Kingdom ("UK") taxation rate on future income tax liabilities as well as share based compensation, risk management activities, and fluctuations in foreign exchange rates. Excluding these items, adjusted net earnings from operations for Q1/11 was $228 million, compared to adjusted net earnings of $639 million in Q1/10 and $585 million in Q4/10. The decrease in adjusted net earnings from Q1/10 and Q4/10 is primarily related to lower SCO sales revenues and continuation of operating costs as a result of the suspension of production from Horizon.

- Record quarterly primary heavy crude oil production of approximately 97,000 bbl/d was achieved in Q1/11. Primary heavy crude oil production increased 6% from the same period last year reflecting the good results from expanded drilling programs in 2010 and 2011. In Q1/11, Canadian Natural drilled 203 net primary heavy crude oil wells. The Company targets to drill a record 827 net primary heavy crude oil wells in 2011 which will drive a targeted 13% production growth in primary heavy crude oil.

- A continued focus on efficient and effective operations in Q1/11 resulted in a 6% per barrel reduction in crude oil and NGLs production expense in the Company's North America Exploration and Production operations when compared to the same period last year.

- A continued focus on effective and efficient operations has led to reductions in full year 2011 operating cost guidance for both North America Natural Gas and in the North Sea crude oil and NGLs.

- International operations in the North Sea and Offshore Africa provided cash flow from operations in Q1/11 of approximately $260 million against capital expenditures of $74 million. International operations provide exposure to Brent oil pricing and the Company targets additional significant free cash flow from the International operations in 2011.

- Repair efforts at Horizon continued and several positive steps have been safely completed in the quarter such as removal of the derrick above Coke Drums 1A and 1B and repairs to the derrick above Coke Drums 2A and 2B. At this stage repairs to the first pair of Coke Drums, 2A and 2B, are targeted for completion in mid-June 2011 which will be immediately followed by several weeks of commissioning and start-up. Once the first pair of Coke Drums is onstream, production rates are targeted to be 55,000 bbl/d of SCO. Repairs to the second pair of Coke Drums, 1A and 1B, are targeted for completion in mid Q3/11 which will be immediately followed by approximately one week of commissioning and start-up of these Drums and returned to full targeted levels of SCO production.

- Construction of the third Ore Preparation Plant ("OPP") at Horizon is currently anticipated to be completed on budget and slightly ahead of schedule. The commissioning of this third plant is currently targeted for Q3/11 and is expected to greatly increase production reliability at Horizon.

- The UK government's implementation of tax increases in the North Sea will result in a 24% reduction in the UK North Sea after-tax profits. Consequently, the Company has immediately curtailed reinvestment activity in the North Sea due to reduced economics. The Company will now only maintain one drilling string in the North Sea, down from the two drilling strings originally planned. The originally planned drilling activity at Murchison during 2011 will be cancelled and plans to contract a subsea vessel in 2012 will also be dropped. Additionally the Company will accelerate its plans to commence decommissioning of the Murchison platform. The Company will continue to high grade all North Sea prospects for potential future development opportunities. In Q1/11 the North Sea represented 6% of total Company production.

- Declared a quarterly cash dividend on common shares of $0.09 per common share payable July 1, 2011.

- Subsequent to quarter end, production at the Olowi Field has been temporarily suspended as a result of a failure of its mid water arch, a support buoy which provides support for production and gas lift flowlines and the main power line. All necessary safety and environmental precautions were undertaken to temporarily stop operations. Current activities are being monitored and a full evaluation is being completed. As a result, the high end of the production guidance for Offshore Africa has been reduced by 2,000 bbl/d for 2011.

## OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in core regions where it can dominate the land base and infrastructure. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Further, the Company maintains large project inventories and production diversification among each of the commodities it produces; namely natural gas, light/medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), synthetic crude oil and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

## OPERATIONS REVIEW

### Drilling activity (number of wells)

| | Three Months Ended Mar 31 | | | |
|---|---|---|---|---|
| | **2011** | | 2010 | |
| | **Gross** | **Net** | Gross | Net |
| Crude oil | **290** | **279** | 256 | 243 |
| Natural gas | **28** | **25** | 52 | 45 |
| Dry | **17** | **16** | 15 | 14 |
| Subtotal | **335** | **320** | 323 | 302 |
| Stratigraphic test / service wells | **502** | **501** | 298 | 297 |
| Total | **837** | **821** | 621 | 599 |
| Success rate (excluding stratigraphic test / service wells) | | **95%** | | 95% |

### North America Exploration and Production

*North America natural gas*

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| Natural gas production (MMcf/d) | **1,225** | 1,223 | 1,193 |
| Net wells targeting natural gas | **26** | 19 | 49 |
| Net successful wells drilled | **25** | 18 | 45 |
| Success rate | **96%** | 95% | 92% |

- Q1/11 North America natural gas production volumes were up 3% from Q1/10 as a result of production at the Company's Septimus property in Northeast British Columbia and natural gas volumes acquired in 2010 and were comparable to Q4/10 levels. The Company continues to implement a small and focused natural gas drilling program that centers on optimizing operations.

- Canadian Natural targeted 26 net natural gas wells in Q1/11. This included 2 net wells drilled in Northeast British Columbia, 16 net wells drilled in Northwest Alberta and 8 net wells drilled in the Northern Plains regions.

- Planned drilling activity for Q2/11 includes 11 net natural gas wells.

- The natural gas capital expenditure budget for 2011 has been increased by $150 million to reflect increased drilling in the Company's liquids rich unconventional natural gas plays at Septimus, Edson and Wild Hay and increased related infrastructure projects to reduce operating costs, increase liquids yields and maximize facility utilization.

*North America crude oil and NGLs*

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| Crude oil and NGLs production (bbl/d) | **290,130** | 286,698 | 252,450 |
| | | | |
| Net wells targeting crude oil | **293** | 323 | 250 |
| Net successful wells drilled | **279** | 316 | 240 |
| Success rate | **95%** | 98% | 96% |

- Q1/11 North America crude oil and NGLs production increased 15% and 1% from Q1/10 and Q4/10 levels respectively. The increase from the same quarter last year reflects increases in all growth areas of crude oil and NGLs production in North America and in particular, in the Company's primary heavy crude oil and thermal operations.

- Record quarterly primary heavy crude oil production of approximately 97,000 bbl/d was achieved in Q1/11. Primary heavy crude oil production increased 6% from the same period last year.

- Strong economics and drilling results in both primary heavy crude oil and light crude oil in Q1/11 have resulted in increases to targeted North America Exploration and Production crude oil and NGLs capital spending of $130 million for 2011.

- A continued focus on efficient and effective operations in Q1/11 resulted in a 6% reduction in crude oil and NGLs production expense when compared to the same period last year.

- Development of new pads continue on track at Primrose South, Primrose North and Primrose East.

- Construction of Kirby South Phase 1 ("Kirby") continued in Q1/11 and targeted timelines and capital expenditures remain on track. Drilling for production capable wells is targeted to commence at Kirby in early May 2011. Kirby's first steam-in is targeted for late 2013 and production is targeted to peak at 40,000 bbl/d. The overall cost of Kirby South Phase 1 is targeted to be $1.25 billion.

- Expansion of the tertiary recovery conversion projects at Pelican Lake continued in Q1/11. The Company drilled 6 horizontal wells in Q1/11 at Pelican Lake with plans to drill a total of 37 horizontal wells in 2011. Production averaged approximately 39,000 bbl/d for Q1/11, compared to approximately 37,000 bbl/d and 38,000 bbl/d for Q1/10 and Q4/10 respectively. The planned 2011 expansion of the polymer flood into new areas of the pool will now occur later than forecast due to delays in receiving regulatory approvals. Injection pressures have also been restricted by the regulators in some portions of the field resulting in delayed oil response due to reduced polymer injection. Polymer flood production response is typically seen 18 to 24 months from injection of polymer flood and production increases from the Company's 2010 program are expected in late 2011/early 2012. Canadian Natural targets to have close to 90% of the field under polymer flood by 2015. Response times for the leading edge polymer flood at Pelican Lake are taking longer than anticipated in South Pelican reflecting slightly different geological characteristics than the portions of the pool previously polymer flooded. Although this has affected the short-term production profile for the pool, the results indicate that the oil recoveries could be higher than expected over the long-run.

- During Q1/11, drilling activity targeted 293 net crude oil wells including 203 wells targeting heavy crude oil, 25 wells in the Greater Pelican Lake area targeting Pelican Lake crude oil, 31 wells targeting bitumen (thermal oil) and 34 wells targeting light crude oil.

- Planned drilling activity for Q2/11 includes 155 net crude oil wells, excluding stratigraphic test and service wells. The Company targets 11% production growth in North America Exploration and Production crude oil and NGLs in 2011.

**International Exploration and Production**

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| Crude oil production (bbl/d) | | | |
| North Sea | **34,101** | 31,701 | 36,879 |
| Offshore Africa | **25,488** | 27,706 | 29,942 |
| Natural gas production (MMcf/d) | | | |
| North Sea | **9** | 9 | 15 |
| Offshore Africa | **22** | 20 | 18 |
| Net wells targeting crude oil | **0.9** | 2.4 | 2.8 |
| Net successful wells drilled | **0.0** | 2.4 | 2.8 |
| Success rate | **0%** | 100% | 100% |

*North Sea*

- North Sea production was 34,101 bbl/d during the quarter, in line with Corporate guidance. Q1/11 crude oil production decreased 8% from Q1/10 as a result of natural declines and increased 8% from Q4/10 as a result of additional production from a Ninian Field well that came on production in late 2010.
- The UK government's implementation of tax increases in the North Sea will result in a 24% reduction in the UK North Sea after-tax profits. Consequently, the Company has immediately curtailed reinvestment activity in the North Sea due to reduced economics. The Company will now only maintain one drilling string in the North Sea, down from the two drilling strings originally planned. The originally planned drilling activity at Murchison during 2011 will be cancelled and plans to contract a subsea vessel in 2012 will also be dropped. Additionally the Company will accelerate its plans to commence decommissioning of the Murchison platform. The Company will continue to high grade all North Sea prospects for potential future development opportunities. In Q1/11 the North Sea represented 6% of total Company production levels.

*Offshore Africa*

- In Q1/11, crude oil production at Offshore Africa was 25,488 bbl/d, a decrease of 15% from Q1/10 as a result of natural declines and a decrease of 8% from Q4/10 due to maintenance activity in the Espoir and Baobab Fields.
- Subsequent to quarter end, production at the Olowi Field has been temporarily suspended as a result of a failure of its mid water arch, a support buoy which provides support for production and gas lift flowlines and the main power line. All necessary safety and environmental precautions were undertaken to temporarily stop operations. Current activities are being monitored and a full evaluation is being completed. As a result, the high end of the production guidance for Offshore Africa has been reduced by 2,000 bbl/d for 2011.

- **North America Oil Sands Mining and Upgrading – Horizon**

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| Synthetic crude oil production (bbl/d) | **7,269** | 92,730 | 86,995 |

- Horizon SCO production averaged 7,269 bbl/d in Q1/11 and was negatively impacted by a fire in the Company's primary upgrading plant in early January 2011.

- The Company announced the re-profiling of Horizon's expansion in Q4/10. The expansion will be executed in a staged project execution plan. Project capital will be allocated to several different modules. Total project capital expenditures (excluding any expenditures for repairs due to the fire) on Horizon in 2011 will range between $715 million and $820 million dependent upon favorability of market conditions and whether the business case meets the Company's investment criteria.

- Construction of the third OPP at Horizon is currently anticipated to be completed on budget and slightly ahead of schedule. The commissioning of this third plant is currently targeted for Q3/11 and is expected to greatly increase reliability.

- The Company is continuing restoration of production from the fire at its primary upgrading plant at Horizon, which occurred on January 6, 2011. Specific items include:

  - The derrick above Coke Drums 1A and 1B where the fire occurred has been successfully dismantled and fabrication of the new derrick has commenced. Repairs on the derrick above Coke Drums 2A and 2B have been completed.
  - Most of the coke cutting components for Coke Drums 2A and 2B have been received. Installation of the coke cutting system is currently in progress.
  - Repair of the cutting deck structure is underway.
  - Repairs of collateral damage to the coker furnace units are proceeding as expected.

- All other identified repairs are underway. At this stage repairs to the first pair of Coke Drums, 2A and 2B, are targeted for completion in mid-June 2011 which will be immediately followed by several weeks of commissioning and start-up. Once the first pair of Coke Drums is onstream, production rates are targeted to be 55,000 bbl/d of SCO. Repairs to the second pair of Coke Drums, 1A and 1B, are targeted for completion in mid Q3/11 which will be immediately followed by approximately one week of commissioning and start-up of these Drums and returned to full targeted levels of SCO production.

- Turnaround and opportune maintenance is well underway and is targeted to be complete well before start-up. Portions of the turnaround originally scheduled for 2012 have been accelerated and remaining portions of that turnaround are now expected to be deferred to 2013, which will result in higher targeted production levels of SCO for 2012 than previously forecast.

- Fire repair/rebuild costs, including associated damage, are currently estimated at approximately $350 million to $450 million. The Company will continue to provide updates as the repair progresses.

- The Company maintains an insurance program which it expects to adequately cover the cost of the repair/rebuild, as well as, maintaining business interruption insurance to alleviate a portion of ongoing operating costs, thereby reducing the financial impacts of the incident.

## MARKETING

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| Crude oil and NGLs pricing | | | |
| WTI[1] benchmark price (US$/bbl) | **$ 94.25** | $ 85.18 | $ 78.79 |
| Western Canadian Select blend differential from WTI (%) | **24%** | 21% | 12% |
| SCO price (US$/bbl) | **$ 95.24** | $ 83.14 | $ 79.37 |
| Average realized pricing before risk management[2] (C$/bbl) | **$ 67.96** | $ 67.74 | $ 68.76 |
| Natural gas pricing | | | |
| AECO benchmark price (C$/GJ) | **$ 3.57** | $ 3.39 | $ 5.07 |
| Average realized pricing before risk management (C$/Mcf) | **$ 3.83** | $ 3.56 | $ 5.19 |

*(1) Refers to West Texas Intermediate (WTI) crude oil barrel priced at Cushing, Oklahoma.*

*(2) Excludes SCO.*

- In Q1/11, the Western Canadian Select ("WCS") heavy crude oil differential as a percent of WTI was 24%. WTI pricing increased by $15.46/bbl in Q1/11 from Q1/10, however, the impact of pipeline disruptions and subsequent logistical constraints in the United States in late 2010/early 2011 resulted in the heavy differential widening from 12% in Q1/10 to 24% in Q1/11. This, combined with a stronger Canadian dollar resulted in a marginal decrease to the Company's crude oil and NGLs average realized pricing (before risk management and excluding SCO) over the same period.
- During Q1/11, the Company contributed approximately 205,000 bbl/d of its heavy crude oil streams to the WCS blend. Canadian Natural is the largest contributor accounting for 61% of the WCS blend.

## REDWATER UPGRADING AND REFINING

- In Q1/11, Canadian Natural announced that it has partnered with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of the bitumen refinery. In addition, the partnership has entered into an agreement to process bitumen supplied by the Government of Alberta under its Bitumen Royalty In Kind ("BRIK") initiative. The project engineering is advancing and work towards sanction level completion is ongoing. Sanction is currently targeted for the latter part of 2011 or the first half of 2012.

## FINANCIAL REVIEW

- The financial position of the Company remains strong as the Company continues to focus on capital discipline. Canadian Natural continually examines its liquidity position and targets a low risk approach to finance. The Company's commodity hedging program, its existing credit facilities and capital expenditure programs all support a flexible financial position:
  - A large and diverse asset base spread over various commodity types - produced in excess of 560,000 BOE/d in Q1/11, with 95% of production located in G8 countries.
  - Financial stability and liquidity - cash flow from operations of $1.07 billion in Q1/11 with available unused bank lines of $2.3 billion at March 31, 2011. The Company believes that its capital resources and large balanced operations are sufficient to compensate for any short-term cash flow reductions arising from the suspension of Horizon production, and accordingly, the Company's targeted capital program currently remains unchanged for 2011.
  - Flexibility in asset base allows for a disciplined capital allocation program.
- A strong balance sheet with debt to book capitalization of 29% and debt to EBITDA of 1.1 times.
- A diverse asset base with strong cash flow generation and the strengthening of the Canadian dollar resulted in the Company exiting Q1/11 with a long-term debt balance of approximately $8.5 billion in Q1/11 comparable to Q4/10 of approximately $8.5 billion with minimal production from Horizon in the first quarter of 2011.

- Declared a quarterly cash dividend on common shares of $0.09 per common share payable July 1, 2011.
- Canadian Natural was surprised and disappointed by the actions of the United Kingdom's Chancellor of the Exchequer in his annual budget in March 2011, when income taxes were again increased for the crude oil and natural gas industry resulting in a 24% reduction of crude oil and natural gas after-tax profits to Exploration and Production companies in the UK North Sea. We believe this action is short-sighted and will result in reduced investment and job losses in the North Sea and a deterioration of the North Sea crude oil and natural gas reserve life index. This represents the third increase in the taxation of crude oil and natural gas profits in the United Kingdom since 2002.

## OUTLOOK

The Company forecasts 2011 production levels before royalties to average between 1,203 and 1,270 MMcf/d of natural gas and between 381,000 and 421,000 bbl/d of crude oil and NGLs. Q2/11 production guidance before royalties is forecast to average between 1,219 and 1,244 MMcf/d of natural gas and between 345,000 and 375,000 bbl/d of crude oil and NGLs. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

### Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes and costs, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands resumption of production and future expansion, ability to recover insurance proceeds, Primrose, Pelican Lake, Olowi Field (Offshore Gabon), the Kirby Thermal Oil Sands Project, the Keystone Pipeline US Gulf Coast expansion, and the construction and operation of the North West Redwater bitumen refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and natural gas liquids ("NGLs") not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management's estimates or opinions change.

**Management's Discussion and Analysis**

Management's Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2011 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2010.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. Common share data and per common share amounts have been restated to reflect the two-for-one share split in May 2010. The Company's consolidated financial statements for the period ended March 31, 2011 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). Unless otherwise stated, prior period amounts have been restated in accordance with IFRS issued as at May 5, 2011. Any subsequent changes to IFRS that are given effect in the Company's annual consolidated financial statements for the year ending December 31, 2011 could result in restatement of the prior periods. This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, and cash production costs. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

The calculation of barrels of oil equivalent ("BOE") is based on a conversion ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent the value equivalency at the wellhead.

Production volumes and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of transportation and blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion refers primarily to the Company's financial results for the three months ended March 31, 2011 in relation to the comparable period in 2010 and the fourth quarter of 2010. The accompanying tables form an integral part of this MD&A. This MD&A is dated May 5, 2011. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2010, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov.

## FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010[1] |
| Product sales | **$ 3,302** | $ 3,787 | $ 3,580 |
| Net earnings (loss) | **$ 46** | $ (309) | $ 735 |
| Per common share – basic | **$ 0.04** | $ (0.28) | $ 0.68 |
| – diluted | **$ 0.04** | $ (0.28) | $ 0.67 |
| Adjusted net earnings from operations [2] | **$ 228** | $ 585 | $ 639 |
| Per common share – basic | **$ 0.21** | $ 0.54 | $ 0.59 |
| – diluted | **$ 0.21** | $ 0.53 | $ 0.58 |
| Cash flow from operations [3] | **$ 1,074** | $ 1,652 | $ 1,507 |
| Per common share – basic | **$ 0.98** | $ 1.52 | $ 1.39 |
| – diluted | **$ 0.97** | $ 1.50 | $ 1.38 |
| Capital expenditures, net of dispositions | **$ 1,694** | $ 1,945 | $ 1,076 |

*(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.*

*(2) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presented below lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.*

*(3) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presented below lists certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.*

### *Adjusted Net Earnings from Operations*

| | *Three Months Ended* | | |
|---|---|---|---|
| *($ millions)* | ***Mar 31 2011*** | *Dec 31 2010* | *Mar 31 2010* |
| *Net earnings (loss) as reported* | ***$ 46*** | *$ (309)* | *$ 735* |
| *Share-based compensation expense, net of tax [(a) (e)]* | ***128*** | *266* | *29* |
| *Unrealized risk management loss (gain), net of tax [(b)]* | ***39*** | *136* | *(156)* |
| *Unrealized foreign exchange gain, net of tax [(c)]* | ***(89)*** | *(102)* | *(101)* |
| *Gabon, Offshore Africa ceiling test impairment [(d)]* | **–** | *594* | *–* |
| *Effect of statutory tax rate and other legislative changes on deferred income tax liabilities [(e)]* | ***104*** | *–* | *132* |
| *Adjusted net earnings from operations* | ***$ 228*** | *$ 585* | *$ 639* |

*(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.*

*(b) Derivative financial instruments are recorded at fair value on the balance sheets, with changes in fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.*

*(c) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, offset by the impact of cross currency swaps, and are recognized in net earnings.*

*(d) The Company recognized a pre-tax ceiling test impairment charge of $637 million ($594 million after-tax) at December 31, 2010.*

*(e) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted or enacted. During the first quarter of 2011, the UK government substantively enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. The Company's deferred income tax liability was increased by $104 million with respect to this tax rate change. During the first quarter of 2010, the Canadian Federal budget enacted changes to the taxation of stock options surrendered by employees for cash payments. As a result of the changes, the Company anticipates that Canadian based employees will no longer surrender their options for cash payments, resulting in a loss of future income tax deductions for the Company. The impact of this change was a $132 million charge to deferred income tax expense.*

***Cash Flow from Operations***

| *($ millions)* | *Three Months Ended* ***Mar 31 2011*** | *Dec 31 2010* | *Mar 31 2010* |
|---|---|---|---|
| *Net earnings (loss)* | ***$ 46*** | *$ (309)* | *$ 735* |
| *Non-cash items:* | | | |
| *Depletion, depreciation and amortization* | ***849*** | *1,546* | *797* |
| *Share-based compensation expense* | ***128*** | *266* | *29* |
| *Asset retirement obligation accretion* | ***33*** | *31* | *30* |
| *Unrealized risk management loss (gain)* | ***54*** | *180* | *(210)* |
| *Unrealized foreign exchange gain* | ***(89)*** | *(116)* | *(116)* |
| *Deferred income tax expense* | ***53*** | *54* | *242* |
| *Horizon asset impairment provision* | ***396*** | *–* | *–* |
| *Insurance recovery* | ***(396)*** | *–* | *–* |
| *Cash flow from operations* | ***$ 1,074*** | *$ 1,652* | *$ 1,507* |

## SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the first quarter of 2011 were $46 million compared to $735 million for the first quarter of 2010 and a net loss of $309 million for the prior quarter. Net earnings for the first quarter of 2011 included net unrealized after-tax expenses of $182 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities, compared to net unrealized after-tax income of $96 million for the first quarter of 2010, and net unrealized after-tax expenses of $894 million for the prior quarter. Excluding these items, adjusted net earnings from operations for the first quarter of 2011 were $228 million, compared to $639 million for the first quarter of 2010 and $585 million for the prior quarter.

The decrease in adjusted net earnings from the first quarter of 2010 was primarily due to lower synthetic crude oil ("SCO") sales revenue and continuing production expenses associated with the suspension of production at Horizon. On January 6, 2011, a fire occurred at the Company's primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received. Other factors contributing to the decrease were:

- lower natural gas netbacks;
- higher depletion, depreciation and amortization expense;
- higher realized risk management losses; and
- the impact of the stronger Canadian dollar;

partially offset by higher North America crude oil and NGL sales volumes.

The decrease in adjusted net earnings from the prior quarter was also primarily due to lower SCO sales revenue and continuing production expenses associated with the suspension of production at Horizon. Other factors contributing to the decrease were:

- higher depletion, depreciation and amortization expense;
- higher realized risk management losses; and
- the impact of the stronger Canadian dollar.

The impacts of share-based compensation, unrealized risk management activities and changes in foreign exchange rates are expected to continue to contribute to quarterly volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the first quarter of 2011 was $1,074 million compared to $1,507 million for the first quarter of 2010 and $1,652 million for the prior quarter. The decrease in cash flow from operations from the first quarter of 2010 was primarily due to lower SCO sales revenue and continuing production expenses associated with the suspension of production at Horizon. Other factors contributing to the decrease were:

- lower natural gas netbacks;
- higher realized risk management losses; and
- the impact of the stronger Canadian dollar;

partially offset by

- higher North America crude oil and NGL sales volumes; and
- lower cash taxes.

The decrease in cash flow from operations from the prior quarter was also primarily due to the lower SCO sales revenue and continuing production expenses associated with the suspension of production at Horizon. Other factors contributing to the decrease were:

- lower crude oil and NGL sales volumes from the North Sea and Offshore Africa;
- higher realized risk management losses; and
- the impact of the stronger Canadian dollar.

Total production before royalties for the first quarter of 2011 decreased 7% to 566,231 BOE/d from 610,556 BOE/d for the first quarter of 2010 and 13% from 647,441 BOE/d for the prior quarter. Production for the first quarter of 2011 was within the Company's previously issued guidance.

**SUMMARY OF QUARTERLY RESULTS**

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

| ($ millions, except per common share amounts) | **Mar 31 2011** | Dec 31 2010 | Sep 30 2010 | Jun 30 2010 |
|---|---|---|---|---|
| Product sales | **$ 3,302** | $ 3,787 | $ 3,341 | $ 3,614 |
| Net earnings (loss) | **$ 46** | $ (309) | $ 596 | $ 651 |
| Net earnings (loss) per common share | | | | |
| – Basic | **$ 0.04** | $ (0.28) | $ 0.55 | $ 0.60 |
| – Diluted | **$ 0.04** | $ (0.28) | $ 0.54 | $ 0.60 |

| ($ millions, except per common share amounts) | Mar 31 2010(1) | Dec 31 2009(1)(2) | Sep 30 2009(1)(2) | Jun 30 2009(1)(2) |
|---|---|---|---|---|
| Product sales | $ 3,580 | $ 3,319 | $ 2,823 | $ 2,750 |
| Net earnings | $ 735 | $ 455 | $ 658 | $ 162 |
| Net earnings per common share | | | | |
| – Basic | $ 0.68 | $ 0.42 | $ 0.61 | $ 0.15 |
| – Diluted | $ 0.67 | $ 0.42 | $ 0.61 | $ 0.15 |

*(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.*

*(2) 2009 quarterly results are reported in accordance with Canadian generally accepted accounting principles as previously reported.*

Volatility in the quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – The impact of fluctuating demand, inventory storage levels and geopolitical uncertainties on worldwide benchmark pricing, and the impact of the WCS Heavy Differential ("WCS Differential") from WTI in North America.
- **Natural gas pricing** – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the impact of the suspension of production at Horizon due to the coker fire incident. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates and the impact of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America, and operations at Horizon and the Olowi Field in Offshore Gabon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, proved reserves, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the impact of the commencement of operations and fire at Horizon and the impact of the commencement of operations and ceiling test impairments at the Olowi Field in Offshore Gabon.
- **Share-based compensation** – Fluctuations due to the mark-to-market movements of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Changes in the Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Fluctuations in unrealized foreign exchange gains and losses are recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

## BUSINESS ENVIRONMENT

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| WTI benchmark price (US$/bbl) [(1)] | **$ 94.25** | $ 85.18 | $ 78.79 |
| Dated Brent benchmark price (US$/bbl) | **$ 105.01** | $ 86.49 | $ 76.32 |
| WCS blend differential from WTI (US$/bbl) | **$ 22.74** | $ 18.15 | $ 9.06 |
| WCS blend differential from WTI (%) | **24%** | 21% | 12% |
| SCO price (US$/bbl) [(2)] | **$ 95.24** | $ 83.14 | $ 79.37 |
| Condensate benchmark price (US$/bbl) | **$ 98.57** | $ 85.18 | $ 84.82 |
| NYMEX benchmark price (US$/MMBtu) | **$ 4.13** | $ 3.81 | $ 5.38 |
| AECO benchmark price (C$/GJ) | **$ 3.57** | $ 3.39 | $ 5.07 |
| US / Canadian dollar average exchange rate | **$ 1.015** | $ 0.9874 | $ 0.9615 |

*(1) West Texas Intermediate ("WTI")*

*(2) Synthetic Crude Oil ("SCO")*

### Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$94.25 per bbl for the first quarter of 2011, an increase of 20% compared to US$78.79 per bbl for the first quarter of 2010, and an increase of 11% from US$85.18 per bbl for the prior quarter. WTI pricing was reflective of the political instability in the Middle East and North Africa, continued strong Asian demand and the relative weakness of the US dollar.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Dated Brent ("Brent") pricing, which is more representative of international markets and overall world supply and demand. Brent averaged US$105.01 per bbl for the first quarter of 2011, an increase of 38% compared to US$76.32 per bbl for the first quarter of 2010, and an increase of 21% from US$86.49 per bbl for the prior quarter. The higher Brent pricing relative to WTI was due to logistical constraints and high inventory levels of crude oil at Cushing.

The WCS Differential averaged 24% for the first quarter of 2011 compared to 12% for the first quarter of 2010, and 21% for the prior quarter. The WCS Differential widened in the first quarter of 2011, compared to the first quarter of 2010, partially due to pipeline disruptions in the last half of 2010 that forced the temporary shutdown and apportionment of major oil pipelines to Midwest refineries in the United States. The differential widened in the first quarter of 2011, compared to the prior quarter, due to unplanned outages at upgrading facilities, increased logistical constraints at Cushing and planned refinery shutdowns in key markets for WCS.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During the first quarter of 2011, condensate prices traded at a premium to WTI, similar to the first quarter of 2010, reflecting normal seasonality. Condensate prices were comparable to WTI in the prior quarter.

The Company anticipates continued volatility in crude oil pricing benchmarks due to supply and demand factors, geopolitical events, and the timing and extent of the continuing economic recovery. The WCS Differential is expected to continue to reflect seasonal demand fluctuations, logistics and refinery margins.

NYMEX natural gas prices averaged US$4.13 per MMBtu for the first quarter of 2011, a decrease of 23% from US$5.38 per MMBtu for the first quarter of 2010, and an increase of 8% from US$3.81 per MMBtu for the prior quarter. AECO natural gas prices averaged $3.57 per GJ for the first quarter of 2011, a decrease of 30% from $5.07 per GJ in the first quarter of 2010, and an increase of 5% from $3.39 per GJ for the prior quarter.

Cold weather in the United States in the first quarter of 2011 resulted in stronger natural gas prices and reduced inventory levels which partially offset strong incremental production from shale gas reservoirs. Overall gas prices continue to be weak in response to the strong North America supply position, primarily from the highly productive shale areas.

**DAILY PRODUCTION, before royalties**

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| **Crude oil and NGLs** (bbl/d) | | | |
| North America – Exploration and Production | **290,130** | 286,698 | 252,450 |
| North America – Oil Sands Mining and Upgrading | **7,269** | 92,730 | 86,995 |
| North Sea | **34,101** | 31,701 | 36,879 |
| Offshore Africa | **25,488** | 27,706 | 29,942 |
| | **356,988** | 438,835 | 406,266 |
| **Natural gas** (MMcf/d) | | | |
| North America | **1,225** | 1,223 | 1,193 |
| North Sea | **9** | 9 | 15 |
| Offshore Africa | **22** | 20 | 18 |
| | **1,256** | 1,252 | 1,226 |
| **Total barrels of oil equivalent** (BOE/d) | **566,231** | 647,441 | 610,556 |
| **Product mix** | | | |
| Light and medium crude oil and NGLs | **21%** | 17% | 19% |
| Pelican Lake heavy crude oil | **7%** | 6% | 6% |
| Primary heavy crude oil | **17%** | 15% | 15% |
| Bitumen (thermal oil) | **17%** | 16% | 12% |
| Synthetic crude oil | **1%** | 14% | 14% |
| Natural gas | **37%** | 32% | 34% |
| **Percentage of product sales** [(1)] (excluding midstream revenue) | | | |
| Crude oil and NGLs | **84%** | 88% | 82% |
| Natural gas | **16%** | 12% | 18% |

*(1) Net of transportation and blending costs and excluding risk management activities.*

**DAILY PRODUCTION, net of royalties**

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| **Crude oil and NGLs** (bbl/d) | | | |
| North America – Exploration and Production | **233,554** | 223,034 | 206,094 |
| North America – Oil Sands Mining and Upgrading | **6,978** | 89,530 | 83,918 |
| North Sea | **34,008** | 31,644 | 36,803 |
| Offshore Africa | **23,213** | 25,291 | 28,927 |
| | **297,753** | 369,499 | 355,742 |
| **Natural gas** (MMcf/d) | | | |
| North America | **1,197** | 1,206 | 1,101 |
| North Sea | **9** | 9 | 15 |
| Offshore Africa | **19** | 18 | 17 |
| | **1,225** | 1,233 | 1,133 |
| **Total barrels of oil equivalent** (BOE/d) | **501,914** | 574,959 | 544,553 |

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely natural gas, light and medium crude oil and NGLs, Pelican Lake heavy crude oil, primary heavy crude oil, bitumen (thermal oil), and SCO.

Total crude oil and NGLs production for the first quarter of 2011 decreased 12% to 356,988 bbl/d from 406,266 bbl/d for the first quarter of 2010, and 19% from 438,835 bbl/d for the prior quarter. The decrease from the first quarter of 2010 and the prior quarter was related to the suspension of production at Horizon, partially offset by the results of the impact of a record heavy oil drilling program and the cyclic nature of the Company's thermal operations. Crude oil and NGLs production in the first quarter of 2011 was within the Company's previously issued guidance of 348,000 to 365,000 bbl/d.

Natural gas production for the first quarter of 2011 averaged 1,256 MMcf/d and increased 2% from the first quarter of 2010 and was comparable to the prior quarter. The increase in natural gas production from the first quarter of 2010 reflects the new production volumes from the Septimus facility in North East British Columbia and from natural gas producing properties acquired during 2010. These increases were partially offset by expected production declines due to the allocation of capital to higher return crude oil projects, which resulted in a strategic reduction of natural gas drilling activity. Natural gas production in the first quarter of 2011 was within the Company's previously issued guidance of 1,249 to 1,273 MMcf/d.

For 2011, revised annual production guidance is targeted to average between 381,000 and 421,000 bbl/d of crude oil and NGLs and between 1,203 and 1,270 MMcf/d of natural gas. Second quarter 2011 production guidance is targeted to average between 345,000 and 375,000 bbl/d of crude oil and NGLs and between 1,219 and 1,244 MMcf/d of natural gas.

**North America – Exploration and Production**

For the first quarter of 2011, crude oil and NGLs production increased 15% to average 290,130 bbl/d, compared to 252,450 bbl/d for the first quarter of 2010, and increased 1% compared to 286,698 bbl/d for the prior quarter. Increases in crude oil and NGLs production from comparable periods were primarily due to the impact of a record heavy oil drilling program and the cyclic nature of the Company's thermal operations. Production of crude oil and NGLs was within the Company's previously issued guidance of 285,000 bbl/d to 295,000 bbl/d for the first quarter of 2011.

For the first quarter of 2011, natural gas production of 1,225 MMcf/d increased 3% compared to the first quarter of 2010 and was comparable to the prior quarter. The increase in natural gas production in the first quarter of 2011 from the comparable period in 2010 reflected new production volumes from the Septimus facility in North East British Columbia and from natural gas producing properties acquired during 2010. These increases were partially offset by expected production declines due to the allocation of capital to higher return crude oil projects, which resulted in a strategic reduction of natural gas drilling activity. Production of natural gas was within the Company's previously issued guidance of 1,220 MMcf/d to 1,240 MMcf/d for the first quarter of 2011.

**North America – Oil Sands Mining and Upgrading**

For the first quarter of 2011, production averaged 7,269 bbl/d, decreasing by 92% compared to 86,995 bbl/d for the first quarter of 2010 and 92,730 bbl/d for the prior quarter. The decrease reflected the suspension of production of synthetic crude oil in January following the occurrence of a fire at Horizon's primary upgrading coking plant. First quarter production for 2011 was consistent with the Company's previously issued guidance of 7,000 bbl/d.

**North Sea**

First quarter 2011 North Sea crude oil production decreased 8% to 34,101 bbl/d from 36,879 bbl/d for the first quarter of 2010, and increased 8% from 31,701 bbl/d for the prior quarter. The decrease in production volumes from the first quarter of 2010 was due to natural field declines. The increase in production volumes from the prior quarter was due to a well coming onstream in the Ninian Field at the end of the prior quarter. Production in the first quarter of 2011 was within the Company's previously issued guidance of 32,000 bbl/d to 35,000 bbl/d.

**Offshore Africa**

First quarter crude oil production averaged 25,488 bbl/d, decreasing 15% from 29,942 bbl/d for the first quarter of 2010 and 8% from 27,706 bbl/d for the prior quarter. The decrease in production volumes from the first quarter of 2010 was due to natural field declines. The decrease in production volumes from the prior quarter was due to temporary shutdowns on the Espoir and Baobab Fields for maintenance and well intervention activity. Production in the first quarter of 2011 was within the Company's previously issued guidance of 24,000 bbl/d to 28,000 bbl/d.

**Crude Oil Inventory Volumes**

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized on crude oil volumes that were stored in various tanks, pipelines, or floating production, storage and offloading vessels, as follows:

| (bbl) | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
|---|---|---|---|
| North America – Exploration and Production | **–** | 761,351 | 761,351 |
| North America – Oil Sands Mining and Upgrading (SCO) | **802,575** | 1,172,200 | 1,021,028 |
| North Sea | **587,121** | 264,995 | 642,457 |
| Offshore Africa | **645,897** | 404,197 | 898,233 |
| | **2,035,593** | 2,602,743 | 3,323,069 |

## OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| **Crude oil and NGLs** ($/bbl) [(1)] | | | |
| Sales price [(2)] | **$ 67.96** | $ 67.74 | $ 68.76 |
| Royalties | **10.43** | 12.14 | 10.08 |
| Production expense | **14.30** | 13.59 | 14.56 |
| Netback | **$ 43.23** | $ 42.01 | $ 44.12 |
| **Natural gas** ($/Mcf) [(1)] | | | |
| Sales price [(2)] | **$ 3.83** | $ 3.56 | $ 5.19 |
| Royalties | **0.13** | 0.07 | 0.41 |
| Production expense | **1.17** | 1.05 | 1.20 |
| Netback | **$ 2.53** | $ 2.44 | $ 3.58 |
| **Barrels of oil equivalent** ($/BOE) [(1)] | | | |
| Sales price [(2)] | **$ 51.33** | $ 50.41 | $ 53.88 |
| Royalties | **6.87** | 7.83 | 7.07 |
| Production expense | **11.59** | 10.91 | 11.67 |
| Netback | **$ 32.87** | $ 31.67 | $ 35.14 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

*(2) Net of transportation and blending costs and excluding risk management activities.*

## PRODUCT PRICES – EXPLORATION AND PRODUCTION

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| **Crude oil and NGLs** ($/bbl) [1] [2] | | | |
| North America | **$ 62.21** | $ 63.62 | $ 66.18 |
| North Sea | **$ 102.51** | $ 88.05 | $ 80.53 |
| Offshore Africa | **$ 97.09** | $ 80.39 | $ 79.30 |
| Company average | **$ 67.96** | $ 67.74 | $ 68.76 |
| **Natural gas** ($/Mcf) [1] [2] | | | |
| North America | **$ 3.77** | $ 3.50 | $ 5.20 |
| North Sea | **$ 3.56** | $ 2.99 | $ 4.30 |
| Offshore Africa | **$ 7.34** | $ 7.59 | $ 5.56 |
| Company average | **$ 3.83** | $ 3.56 | $ 5.19 |
| **Company average** ($/BOE) [1] [2] | **$ 51.33** | $ 50.41 | $ 53.88 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

*(2) Net of transportation and blending costs and excluding risk management activities.*

### North America

North America realized crude oil prices averaged $62.21 per bbl for the first quarter of 2011, a decrease of 6% compared to $66.18 per bbl for the first quarter of 2010 and a decrease of 2% compared to $63.62 per bbl for the prior quarter. The decrease in prices from the first quarter of 2010 and the prior quarter was primarily a result of the widening WCS Differential and the impact of the stronger Canadian dollar relative to the US dollar, partially offset by increased WTI benchmark pricing.

The Company continues to focus on its crude oil blending marketing strategy, and in the first quarter of 2011 contributed approximately 205,000 bbl/d of heavy crude oil blends to the WCS stream.

In the first quarter of 2011, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen refinery near Redwater, Alberta. In addition, the partnership has entered into an agreement to process bitumen supplied by the Government of Alberta under the Alberta Royalty Framework's Bitumen Royalty In Kind initiative. Project development is dependent upon completion of this detailed engineering and final project sanction by the respective parties. Board sanction is currently targeted for the latter half of 2011 or the first half of 2012.

North America realized natural gas prices averaged $3.77 per Mcf for the first quarter of 2011, a decrease of 28% compared to $5.20 per Mcf for the first quarter of 2010 and an increase of 8% from $3.50 per Mcf for the prior quarter. The decrease in natural gas prices from the first quarter of 2010 was primarily related to the impact of strong supply from US shale projects and continued weak demand from the industrial sector, together with the impact of a stronger Canadian dollar. The increase in natural gas prices from the prior quarter was primarily related to higher benchmark prices as a result of a colder than normal winter in North America.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

| (Quarterly Average) | | **Mar 31 2011** | | Dec 31 2010 | | Mar 31 2010 |
|---|---|---|---|---|---|---|
| **Wellhead Price** (1) (2) | | | | | | |
| Light and medium crude oil and NGLs ($/bbl) | **$** | **76.57** | $ | 69.77 | $ | 72.15 |
| Pelican Lake heavy crude oil ($/bbl) | **$** | **62.78** | $ | 61.73 | $ | 66.04 |
| Primary heavy crude oil ($/bbl) | **$** | **59.62** | $ | 62.62 | $ | 66.45 |
| Bitumen (thermal oil) ($/bbl) | **$** | **56.79** | $ | 62.10 | $ | 62.08 |
| Natural gas ($/Mcf) | **$** | **3.77** | $ | 3.50 | $ | 5.20 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

*(2) Net of transportation and blending costs and excluding risk management activities.*

### North Sea

North Sea realized crude oil prices averaged $102.51 per bbl for the first quarter of 2011, an increase of 27% from $80.53 per bbl for the first quarter of 2010, and 16% from $88.05 per bbl for the prior quarter. The increase in realized crude oil prices in the North Sea from the comparable periods in 2010 was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

### Offshore Africa

Offshore Africa realized crude oil prices averaged $97.09 per bbl for the first quarter of 2011, an increase of 22% from $79.30 per bbl for the first quarter of 2010, and 21% from $80.39 per bbl in the prior quarter. The increase in realized crude oil prices in Offshore Africa from the comparable periods in 2010 was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

## ROYALTIES – EXPLORATION AND PRODUCTION

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| **Crude oil and NGLs** ($/bbl) (1) | | | |
| North America | **$ 11.61** | $ 14.30 | $ 12.13 |
| North Sea | **$ 0.28** | $ 0.16 | $ 0.17 |
| Offshore Africa | **$ 8.66** | $ 7.01 | $ 2.69 |
| Company average | **$ 10.43** | $ 12.14 | $ 10.08 |
| **Natural gas** ($/Mcf) (1) | | | |
| North America (2) | **$ 0.12** | $ 0.06 | $ 0.41 |
| Offshore Africa | **$ 0.97** | $ 0.69 | $ 0.19 |
| Company average | **$ 0.13** | $ 0.07 | $ 0.41 |
| **Company average** ($/BOE) (1) | **$ 6.87** | $ 7.83 | $ 7.07 |
| **Percentage of product sales** (2) | | | |
| Crude oil and NGLs | **15%** | 18% | 15% |
| Natural gas | **3%** | 2% | 8% |
| BOE | **13%** | 16% | 13% |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

*(2) Net of transportation and blending costs and excluding risk management activities.*

### North America

North America royalties for the three months ended March 31, 2011 compared to 2010 reflected benchmark commodity prices.

Crude oil and NGLs royalties averaged approximately 19% of product sales for the first quarter of 2011, compared to 18% for the first quarter of 2010 and 22% for the prior quarter. The decrease in royalties from the prior quarter was due to crude oil royalty adjustments recorded in the prior quarter. Crude oil and NGLs royalties per bbl are anticipated to average 19% to 22% of product sales for 2011.

Natural gas royalties averaged approximately 3% of product sales for the first quarter of 2011, compared to 8% for the first quarter of 2010 and 2% for the prior quarter. The decrease in natural gas royalty rates compared to the first quarter of 2010 was primarily due to lower benchmark pricing. The increase in natural gas royalty rates from the prior quarter was primarily due to higher benchmark pricing. Natural gas royalties are anticipated to average 2% to 4% of product sales for 2011.

### Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of product sales averaged approximately 9% for the first quarter of 2011 compared to 3% for the first quarter of 2010 and 9% for the prior quarter. Offshore Africa royalty rates are anticipated to increase in 2011 to average 13% to 15% of product sales for 2011, as a result of the expected payout of the Baobab Field.

## PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| **Crude oil and NGLs** ($/bbl) [1] | | | |
| North America | **$ 12.28** | $ 11.41 | $ 13.09 |
| North Sea | **$ 30.46** | $ 30.05 | $ 25.15 |
| Offshore Africa | **$ 19.13** | $ 13.86 | $ 13.49 |
| Company average | **$ 14.30** | $ 13.59 | $ 14.56 |
| **Natural gas** ($/Mcf) [1] | | | |
| North America | **$ 1.16** | $ 1.02 | $ 1.17 |
| North Sea | **$ 2.65** | $ 2.70 | $ 3.54 |
| Offshore Africa | **$ 1.25** | $ 2.00 | $ 1.63 |
| Company average | **$ 1.17** | $ 1.05 | $ 1.20 |
| **Company average** ($/BOE) [1] | **$ 11.59** | $ 10.91 | $ 11.67 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

### North America

North America crude oil and NGLs production expense for the first quarter of 2011 decreased 6% to $12.28 per bbl from $13.09 per bbl for the first quarter of 2010 and increased 8% from $11.41 per bbl for the prior quarter. The decrease in production expense per barrel from the first quarter of 2010 was a result of higher production volumes and the lower cost of natural gas used for fuel. The increase in production expense per barrel from the prior quarter was due to the timing of thermal steam cycles. North America crude oil and NGLs production expense is anticipated to average $12.00 to $13.00 per bbl for 2011.

North America natural gas production expense for the first quarter of 2011 averaged $1.16 per Mcf and was comparable to the first quarter of 2010. Natural gas production expense increased 14% from $1.02 per Mcf for the prior quarter as a result of the impact of normal seasonal costs associated with winter access and colder weather. North America natural gas production expense is anticipated to average $1.05 to $1.15 per Mcf for 2011.

### North Sea

North Sea crude oil production expense for the first quarter of 2011 increased 21% to $30.46 per bbl from $25.15 per bbl for the first quarter of 2010 and was comparable to the prior quarter. Production expense increased on a per barrel basis from the first quarter of 2010 due to lower volumes on relatively fixed costs. Production expense is anticipated to average $37.00 to $41.00 per bbl for 2011.

### Offshore Africa

Offshore Africa crude oil production expense for the first quarter of 2011 averaged $19.13 per bbl, an increase of 42% compared to $13.49 per bbl for the first quarter of 2010 and 38% compared to $13.86 per bbl for the prior quarter. Production expense increased on a per barrel basis from the comparable periods in 2010 due to the timing of liftings for each field, and due to lower volumes on relatively fixed costs. Production expense is anticipated to average $21.00 to $24.00 per bbl for 2011.

## DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
|---|---|---|---|
| Expense ($ millions) | **$ 824** | $ 1,440 | $ 698 |
| $/BOE (1) | **$ 16.33** | $ 27.66 | $ 14.93 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

The increase in depletion, depreciation and amortization expense from the first quarter of 2010 was due to higher production in North America and an increase in the estimated future costs to develop the Company's proved undeveloped reserves. The decrease in depletion, depreciation and amortization expense from the prior quarter was primarily due to the impact of a ceiling test impairment related to Gabon, Offshore Africa at December 31, 2010.

## ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
|---|---|---|---|
| Expense ($ millions) | **$ 28** | $ 24 | $ 23 |
| $/BOE (1) | **$ 0.56** | $ 0.45 | $ 0.49 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

## OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

## OPERATIONS UPDATE

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

## PRODUCT PRICES AND ROYALTIES

| | Three Months Ended | | |
|---|---|---|---|
| ($/bbl) (1) | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| SCO sales price (2) | **$ 82.93** | $ 81.51 | $ 78.76 |
| Bitumen value for royalty purposes (3) | **$ 51.13** | $ 56.42 | $ 61.33 |
| Bitumen royalties (4) | **$ 4.14** | $ 2.77 | $ 2.83 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*
*(2) Net of transportation.*
*(3) Calculated as the simple average of the monthly bitumen valuation methodology price.*
*(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.*

Realized SCO sales prices averaged $82.93 per bbl for the first quarter of 2011, an increase of 5% compared to $78.76 per bbl for the first quarter of 2010 and 2% compared to $81.51 per bbl for the prior quarter. The increase in SCO prices from the first quarter of 2010 and the prior quarter was primarily due to the increase in the WTI benchmark price, offset by the impact of the strengthening Canadian dollar.

## PRODUCTION COSTS

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

| ($ millions) | Three Months Ended<br>**Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
|---|---|---|---|
| Cash costs | **$ 256** | $ 304 | $ 346 |
| Less: costs incurred after suspension of production | **(209)** | – | – |
| Adjusted cash costs | **$ 47** | $ 304 | $ 346 |
| Cash costs, excluding natural gas costs | **42** | 278 | 299 |
| Natural gas costs | **5** | 26 | 47 |
| Total cash production costs | **$ 47** | $ 304 | $ 346 |

| ($/bbl) (1) | Three Months Ended<br>**Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
|---|---|---|---|
| Cash costs, excluding natural gas costs | **$ 41.38** | $ 33.09 | $ 37.29 |
| Natural gas costs | **4.31** | 3.04 | 5.83 |
| Total cash production costs | **$ 45.69** | $ 36.13 | $ 43.12 |
| Sales (bbl/d) | **11,376** | 91,350 | 89,256 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

Total cash production costs averaged $45.69 per bbl in the first quarter of 2011 compared to $43.12 per bbl for the first quarter of 2010, and $36.13 per bbl for the prior quarter. The increase in cash production costs from the first quarter of 2010 and the prior quarter was primarily due to lower production levels.

## DEPLETION, DEPRECIATION AND AMORTIZATION

| ($ millions) | Three Months Ended<br>**Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
|---|---|---|---|
| Depletion, depreciation and amortization | **$ 23** | $ 104 | $ 97 |
| Less: depreciation incurred after suspension of production | **(10)** | – | – |
| Adjusted depletion, depreciation and amortization | **$ 13** | $ 104 | $ 97 |
| $/BOE (1) | **$ 12.37** | $ 12.37 | $ 12.13 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

Depletion, depreciation and amortization decreased from the first quarter of 2010 and the prior quarter primarily due to lower production levels.

## ASSET RETIREMENT OBLIGATION ACCRETION

| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
|---|---|---|---|
| Expense ($ millions) | **$ 5** | $ 7 | $ 7 |
| $/BOE (1) | **$ 4.84** | $ 0.87 | $ 0.91 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

## MIDSTREAM

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions) | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| Revenue | **$ 22** | $ 20 | $ 19 |
| Production expense | **7** | 6 | 5 |
| Midstream cash flow | **15** | 14 | 14 |
| Depreciation | **2** | 2 | 2 |
| Segment earnings before taxes | **$ 13** | $ 12 | $ 12 |

Midstream operating results were consistent with the comparable periods.

## ADMINISTRATION EXPENSE

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| Expense ($ millions) | **$ 54** | $ 54 | $ 54 |
| $/BOE (1) | **$ 1.05** | $ 0.89 | $ 0.99 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

Administration expense for the first quarter of 2011 was comparable to the first quarter of 2010 and the prior quarter.

## SHARE-BASED COMPENSATION EXPENSE

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions) | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| Expense | **$ 128** | $ 266 | $ 29 |

The Company’s stock option plan provides current employees with the right to receive common shares or a direct cash payment in exchange for options surrendered.

The Company recorded a $128 million share-based compensation expense for the three months ended March 31, 2011 primarily as a result of normal course graded vesting of options granted in prior periods, the impact of vested options exercised or surrendered during the period and remeasurement of the fair value of outstanding options at the end of the period. For the three months ended March 31, 2011, the Company capitalized $11 million in share-based compensation to Oil Sands Mining and Upgrading (March 31, 2010 – $6 million).

For the three months ended, March 31, 2011, the Company paid $10 million for stock options surrendered for cash settlement (March 31, 2010 – $36 million).

## INTEREST AND OTHER FINANCING COSTS

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions, except per BOE amounts) | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| Expense, gross | **$ 105** | $ 130 | $ 116 |
| Less: capitalized interest | **11** | 9 | 7 |
| Expense, net | **$ 94** | $ 121 | $ 109 |
| $/BOE (1) | **$ 1.83** | $ 2.00 | $ 2.00 |
| Average effective interest rate | **4.8%** | 5.2% | 4.8% |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*

Gross interest and other financing costs decreased compared to the first quarter of 2010 due to lower overall debt levels and the impact of a stronger Canadian dollar on US dollar denominated debt, partially offset by the impact of higher variable interest rates. Gross interest and other financing costs decreased compared to the prior quarter due to lower overall debt levels and the impact of a stronger Canadian dollar on US dollar denominated debt. The Company's average effective interest rate decreased from the prior quarter primarily due to a decreased weighting of fixed versus lower-cost floating rate debt.

## RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions) | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| Crude oil and NGLs financial instruments | **$ 27** | $ 47 | $ 17 |
| Natural gas financial instruments | **–** | (53) | (18) |
| Foreign currency contracts and interest rate swaps | **43** | 18 | 40 |
| Realized loss | **$ 70** | $ 12 | $ 39 |
| | | | |
| Crude oil and NGLs financial instruments | **$ 67** | $ 108 | $ (73) |
| Natural gas financial instruments | **–** | 51 | (130) |
| Foreign currency contracts and interest rate swaps | **(13)** | 21 | (7) |
| Unrealized loss (gain) | **$ 54** | $ 180 | $ (210) |
| Net loss (gain) | **$ 124** | $ 192 | $ (171) |

Complete details related to outstanding derivative financial instruments at March 31, 2011 are disclosed in note 14 to the Company’s unaudited interim consolidated financial statements.

The Company recorded a net unrealized loss of $54 million ($39 million after-tax) on its risk management activities for the three months ended March 31, 2011 (December 31, 2010 – unrealized loss of $180 million, $136 million after-tax; March 31, 2010 – unrealized gain of $210 million, $156 million after-tax), primarily due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses.

## FOREIGN EXCHANGE

| ($ millions) | Three Months Ended<br>**Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
|---|---|---|---|
| Net realized loss (gain) | **$ 22** | $ 6 | $ (10) |
| Net unrealized gain [(1)] | **(89)** | (116) | (116) |
| Net gain | **$ (67)** | $ (110) | $ (126) |

*(1) Amounts are reported net of the hedging effect of cross currency swaps.*

The net unrealized foreign exchange gain for the three months ended March 31, 2011 was primarily due to the strengthening of the Canadian dollar with respect to US dollar debt. The net unrealized gain for each of the periods presented included the impact of cross currency swaps (three months ended March 31, 2011 – unrealized loss of $48 million, December 31, 2010 – unrealized loss of $71 million, March 31, 2010 – unrealized loss of $59 million). The net realized foreign exchange loss for the three months ended March 31, 2011 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the first quarter at US$1.0290 (December 31, 2010 – US$1.0054; March 31, 2010 – US$0.9846).

## TAXES

| ($ millions, except income tax rates) | Three Months Ended<br>**Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
|---|---|---|---|
| North America [(1)] | **$ 91** | $ 49 | $ 129 |
| North Sea | **46** | 84 | 53 |
| Offshore Africa | **20** | 23 | 6 |
| PRT expense | **8** | 14 | 25 |
| Other taxes | **6** | 6 | 7 |
| Current income tax | **171** | 176 | 220 |
| Deferred income tax expense | **43** | 65 | 241 |
| Deferred PRT expense | **10** | (11) | 1 |
| Deferred income tax | **53** | 54 | 242 |
| | **224** | 230 | 462 |
| Income tax rate and other legislative changes [(2)] | **(104)** | – | (132) |
| | **$ 120** | $ 230 | $ 330 |
| Effective income tax rate on adjusted net earnings from operations[(3)] | **32.7%** | 33.4% | 26.3% |

*(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.*

*(2) Deferred income tax expense in the first quarter of 2011 included a charge of $104 million related to substantively enacted changes in the UK to increase the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. Deferred income tax expense in the first quarter of 2010 included a charge of $132 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash.*

*(3) Excludes the impact of current and deferred PRT expense and other current income tax expense.*

Taxable income from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in periods subsequent to the current reporting period. North America current and deferred income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

In March 2011, the UK government substantively enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. This resulted in an increase to the overall effective corporate tax rate applicable to net operating income from oil and gas activities to 62% for non-PRT paying fields and 81% for PRT paying fields, after allowing for deductions for capital and abandonment expenditures. As a result of the income tax rate change, the Company’s deferred income tax liability was increased by $104 million as at March 31, 2011.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

For 2011, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $350 million to $450 million in Canada and $460 million to $500 million in the North Sea and Offshore Africa.

## NET CAPITAL EXPENDITURES [1]

| ($ millions) | Three Months Ended Mar 31 2011 | Dec 31 2010 | Mar 31 2010 |
|---|---|---|---|
| **Exploration and Evaluation** | | | |
| Net expenditures | **$ 74** | $ 409 | $ 51 |
| **Property, Plant and Equipment** | | | |
| Net property acquisitions | **224** | 489 | 33 |
| Land acquisition and retention | **10** | 12 | 12 |
| Seismic evaluations | **9** | 16 | 11 |
| Well drilling, completion and equipping | **572** | 444 | 442 |
| Production and related facilities | **417** | 311 | 382 |
| Net expenditures | **1,232** | 1,272 | 880 |
| **Total Exploration and Production expenditures** | **1,306** | 1,681 | 931 |
| **Oil Sands Mining and Upgrading:** | | | |
| Horizon Phases 2/3 construction costs | **90** | 100 | 71 |
| Coker rebuild and collateral damage costs | **126** | – | – |
| Sustaining capital | **24** | 48 | 18 |
| Turnaround costs | **55** | – | – |
| Capitalized interest, share-based compensation and other | **20** | 28 | 13 |
| **Total Oil Sands Mining and Upgrading [2]** | **315** | 176 | 102 |
| **Midstream** | **3** | 3 | – |
| **Abandonments [3]** | **64** | 80 | 39 |
| **Head office** | **6** | 5 | 4 |
| **Total net capital expenditures** | **$ 1,694** | $ 1,945 | $ 1,076 |
| **By segment** | | | |
| North America | **$ 1,232** | $ 1,600 | $ 809 |
| North Sea | **41** | 38 | 23 |
| Offshore Africa | **33** | 42 | 99 |
| Other | **–** | 1 | – |
| Oil Sands Mining and Upgrading | **315** | 176 | 102 |
| Midstream | **3** | 3 | – |
| Abandonments [3] | **64** | 80 | 39 |
| Head office | **6** | 5 | 4 |
| **Total** | **$ 1,694** | $ 1,945 | $ 1,076 |

*(1) The net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.*

*(2) Net expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.*

*(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.*

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core regions where it can dominate the land base and infrastructure. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for the three months ended March 31, 2011 were $1,694 million compared to $1,076 million for the three months ended March 31, 2010 and $1,945 million for the prior quarter. The increase in capital expenditures from the first quarter of 2010 was primarily due to the purchase of crude oil and natural gas producing properties in the Company's core regions in Western Canada, an increase in well drilling and completion expenditures related to the Company's heavy oil drilling program, an increase in the Company's abandonment program and costs associated with the coker rebuild and collateral damage resulting from the coker fire. The decrease in capital expenditures from the prior quarter was due to lower property acquisitions, offset by higher spending on drilling activities and production related to the heavy oil drilling program and related facilities and costs associated with the coker rebuild and collateral damage.

**Drilling Activity (number of wells)**

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 | Mar 31 2010 |
| Net successful natural gas wells | **25** | 18 | 45 |
| Net successful crude oil wells | **279** | 318 | 243 |
| Dry wells | **16** | 8 | 14 |
| Stratigraphic test / service wells | **501** | 171 | 297 |
| Total | **821** | 515 | 599 |
| Success rate (excluding stratigraphic test / service wells) | **95%** | 98% | 95% |

**North America**

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 77% of the total capital expenditures for the three months ended March 31, 2011 compared to approximately 79% for the three months ended March 31, 2010 and 86% for the prior quarter.

During the first quarter of 2011, the Company targeted 26 net natural gas wells, including 2 wells in Northeast British Columbia, 16 wells in Northwest Alberta, and 8 wells in the Northern Plains region. The Company also targeted 293 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 203 primary heavy crude oil wells, 25 Pelican Lake heavy crude oil wells, 31 bitumen (thermal oil) wells and 6 light crude oil wells were drilled. Another 28 wells targeting light crude oil were drilled outside the Northern Plains region.

As part of the phased expansion of its In Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. Overall Primrose thermal production for the first quarter of 2011 averaged approximately 98,000 bbl/d, compared to approximately 76,000 bbl/d for the first quarter of 2010 and approximately 104,000 bbl/d for the prior quarter.

The next planned phase of the Company's In Situ Oil Sands Assets expansion is the Kirby South Phase 1 Project. Currently the Company is proceeding with the detailed engineering and design work. During the third quarter of 2010, the Company received final regulatory approval for Phase 1 of the Project. During the fourth quarter of 2010, the Company's Board of Directors sanctioned Kirby South Phase 1. Construction has commenced, with first steam targeted in 2013.

Development of the tertiary recovery conversion projects at Pelican Lake continued in the first quarter of 2011. Drilling included 6 horizontal wells during the quarter. Response from the polymer flood project continues to be positive. Pelican Lake production averaged approximately 39,000 bbl/d for the first quarter of 2011, compared to 37,000 bbl/d for the first quarter of 2010 and 38,000 bbl/d for the prior quarter.

For the second quarter of 2011, the Company's overall planned drilling activity in North America is expected to be comprised of 11 net natural gas wells and 155 net crude oil wells, excluding stratigraphic and service wells.

### Oil Sands Mining and Upgrading

Phase 2/3 spending during the first quarter of 2011 continued to be focused on construction of the third Ore Preparation Plant and associated hydro-transport, additional product tankage, the butane treatment unit and the sulphur recovery unit. Final construction and the commencement of commissioning of the Ore Preparation Plant and associated hydro-transport is currently targeted for the third quarter of 2011.

On January 6, 2011, a fire occurred at the Company's primary upgrading coking plant. The fire was confined to the coke drum structure. Subsequent collateral freeze damage has further impacted recovery efforts. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

As at March 31, 2011, the Company recognized a Horizon asset impairment provision of $396 million, net of accumulated depletion and depreciation, related to the property damage resulting from the fire in the primary upgrading coking plant. As the Company believes that its insurance coverage is adequate to mitigate all significant property damage related losses, estimated insurance proceeds receivable of $396 million were also recognized, offsetting such property damage. The final Horizon asset impairment provision and related insurance recoveries are subject to revision once restoration of plant operating capacity is completed and final costs are determined. Accordingly, actual results may differ significantly from the amounts currently recognized.

The Company also maintains business interruption coverage, subject to a waiting period, which, commencing in the second quarter, it believes will reduce operating losses related to on-going operations.

### North Sea

During the first quarter of 2011, the Company focused on workovers on the Ninian South Platform.

In March 2011, the UK government substantively enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. This resulted in an increase to the overall corporate tax rate applicable to net operating income from oil and gas activities to 62% for non-PRT paying fields and 81% for PRT paying fields, after allowing for deductions for capital and abandonment expenditures.

As a result of the increase in the corporate income tax rate change, the Company’s development activities in the North Sea will be reduced. The Company will now only maintain one drilling string in the North Sea, down from the two originally planned. The planned drilling activity at Murchison during 2011 will be cancelled. The Company will continue to high grade all North Sea prospects for potential future development opportunities.

### Offshore Africa

Production at the Olowi Field has been temporarily suspended as a result of a failure of a buoy which provides support for production and gas lift flowlines and the main power line. All necessary safety and environmental precautions were undertaken to temporarily cease operations. Current activities are being monitored and a full evaluation is currently underway.

## LIQUIDITY AND CAPITAL RESOURCES

| ($ millions, except ratios) | | **Mar 31 2011** | | Dec 31 2010 | | Mar 31 2010 |
|---|---|---|---|---|---|---|
| Working capital (deficit) [(1)] | **$** | **(1,657)** | $ | (1,200) | $ | (767) |
| Long-term debt [(2) (3)] | **$** | **8,468** | $ | 8,485 | $ | 8,936 |
| | | | | | | |
| Share capital | **$** | **3,394** | $ | 3,147 | $ | 2,939 |
| Retained earnings | | **17,158** | | 17,212 | | 16,581 |
| Accumulated other comprehensive loss | | **43** | | 9 | | 33 |
| Shareholders' equity | **$** | **20,595** | $ | 20,368 | $ | 19,553 |
| | | | | | | |
| Debt to book capitalization [(3) (4)] | | **29%** | | 29% | | 31% |
| Debt to market capitalization [(3) (5)] | | **14%** | | 15% | | 18% |
| After-tax return on average common shareholders' equity [(6)] | | **5%** | | 8% | | – |
| After-tax return on average capital employed [(3) (7)] | | **5%** | | 7% | | – |

*(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.*

*(2) Includes the current portion of long-term debt (March 31, 2011 - $389 million, December 31, 2010 - $397 million, March 31, 2010 - $400 million)*

*(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.*

*(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.*

*(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.*

*(6) Calculated as net earnings for the twelve month trailing period; as a percentage of average common shareholders' equity for the period. The ratio for the trailing period ended March 31, 2010 has not been presented as the period would include 2009 amounts based on Canadian GAAP as previously reported and therefore may not be comparable.*

*(7) Calculated as net earnings plus after-tax interest and other financing costs for the twelve month trailing period; as a percentage of average capital employed for the period. The ratio for the trailing period ended March 31, 2010 has not been presented as the period would include 2009 amounts based on Canadian GAAP as previously reported and therefore may not be comparable.*

At March 31, 2011, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's December 31, 2010 annual MD&A**.** The Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon these factors, as well as maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its on-going hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

The Company believes that its capital resources are sufficient to compensate for any short-term cash flow reduction arising from Horizon, and accordingly, the Company's targeted North America capital program has been increased for 2011. At March 31, 2011, the Company had $2,261 million of available credit under its bank credit facilities. During the fourth quarter of 2010, the Company repaid $400 million of the medium-term notes bearing interest at 5.50%. Long-term debt was $8,468 million at March 31, 2011, resulting in a debt to book capitalization ratio of 29% (December 31, 2010 – 29%; March 31, 2010 – 31%). This ratio is below the 35% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, and lower commodity prices occur. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and flexible capital structure. The Company has hedged a portion of its crude oil production for 2011 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs. Further details related to the Company's long-term debt at March 31, 2011 are discussed in note 7 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this program, the purchase of put options is in addition to the above parameters. As at March 31, 2011, in accordance with the policy, approximately 11% of budgeted crude oil volumes were hedged using collars for 2011. Further details related to the Company's commodity related derivative financial instruments outstanding at March 31, 2011 are discussed in note 14 to the Company's unaudited interim consolidated financial statements.

**Share capital**

As at March 31, 2011, there were 1,096,360,000 common shares outstanding and 61,026,000 stock options outstanding. As at May 4, 2011, the Company had 1,096,644,000 common shares outstanding and 60,522,000 stock options outstanding.

On March 1, 2011, the Company's Board of Directors approved an increase in the annual dividend to be paid by the Company to $0.36 per common share for 2011. The increase represents a 20% increase from 2010, recognizing the stability of the Company's cash flow and providing a return to Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

On March 31, 2011, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the TSX and the NYSE, during the 12 month period commencing April 6, 2011 and ending April 5, 2012, up to 27,406,131 common shares or 2.5% of the common shares of the Company outstanding at March 25, 2011. As at May 5, 2011, no common shares had been purchased under this Normal Course Issuer Bid.

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), during the 12 month period commencing April 6, 2010 and ending April 5, 2011, up to 27,163,940 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. A total of 2,000,000 common shares were purchased for cancellation at an average price of $33.77 per common share, for a total cost of $68 million, under this Normal Course Issuer Bid.

**COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS**

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. As at March 31, 2011, no entities were consolidated under the Standing Interpretations Committee 12, "Consolidation – Special Purpose Entities". The following table summarizes the Company's commitments as at March 31, 2011:

| ($ millions) | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter |
|---|---|---|---|---|---|---|
| Product transportation and pipeline | $ 166 | $ 201 | $ 173 | $ 164 | $ 152 | $ 933 |
| Offshore equipment operating leases | $ 110 | $ 96 | $ 95 | $ 95 | $ 79 | $ 164 |
| Long-term debt (1) | $ 389 | $ 1,904 | $ 789 | $ 340 | $ 400 | $ 4,665 |
| Interest and other financing costs (2) | $ 295 | $ 387 | $ 345 | $ 326 | $ 300 | $ 4,129 |
| Office leases | $ 20 | $ 29 | $ 33 | $ 34 | $ 32 | $ 336 |
| Other | $ 104 | $ 67 | $ 19 | $ 18 | $ 24 | $ 10 |

*(1) Long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.*

*(2) Interest and other financing cost amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at March 31, 2011.*

**LEGAL PROCEEDINGS AND OTHER CONTINGENCIES**

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

**INTERNAL CONTROLS OVER FINANCIAL REPORTING**

The Company has identified, developed and tested systems and accounting and reporting processes and changes required to capture data required for IFRS accounting and reporting, including 2010 requirements to capture both Canadian GAAP and IFRS data.

**INTERNATIONAL FINANCIAL REPORTING STANDARDS**

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises would be required to adopt IFRS as issued by the IASB in place of Canadian GAAP effective January 1, 2011.

The Company has completed its transition to IFRS. The 2011 fiscal year is the first year in which the Company has prepared its consolidated financial statements in accordance with IFRS as issued by the IASB. The interim consolidated financial statements for the three months ended March 31, 2011 have been prepared in accordance with IFRS applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34, "Interim Financial Reporting" and IFRS 1, "First-time Adoption of International Financial Reporting Standards".

The accounting policies adopted by the Company under IFRS are set out in note 1 to the interim consolidated financial statements for the three months ended March 31, 2011. Note 18 to the interim consolidated financial statements discloses the impact of the transition to IFRS on the Company's reported financial position, earnings and cash flows, including the nature and effect of certain transition elections and significant changes in accounting policies from those used in the Company's Canadian GAAP consolidated financial statements for 2010.

**ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED**

The Company is required to adopt IFRS 9, "Financial Instruments", effective January 1, 2013, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, "Financial Instruments - Recognition and Measurement". The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

## CRITICAL ACCOUNTING ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from those estimates, and those differences may be material.

Critical accounting estimates are reviewed by the Company's Audit Committee annually. The Company believes the following are the most critical accounting estimates in preparing its consolidated financial statements.

### Depletion, Depreciation and Amortization and Impairment

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment losses. Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

Exploration and evaluation ("E&E") asset costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and costs associated with retiring the assets. Exploration and evaluation assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved reserves are determined to exist. The judgements associated with the estimation of proved reserves are described below in "Crude Oil and Natural Gas Reserves".

An alternative acceptable accounting method for E&E assets under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves, increases in estimated future exploration expenditures, and significant adverse changes in the legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves, increases in estimated future development expenditures, and significant adverse changes in the legislative or regulatory frameworks. If any such indication of impairment exists, the Company performs an impairment test related to the specific assets. Individual assets are grouped for impairment assessment purposes into CGU's, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. The determination of fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

### Crude Oil and Natural Gas Reserves

The estimation of reserves involves the exercise of judgement. Reserve estimates 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 Company expects that, over time, its reserve estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserve estimates would result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates may also result in an impairment of crude oil and natural gas property, plant and equipment carrying amounts.

**Asset Retirement Obligations**

The Company is required to recognize a liability for asset retirement obligations ("ARO") associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions can be subject to change.

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's average credit-adjusted risk-free interest rate, which is currently 5.2%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas increases or decreases due to changes in interest rates and estimated future cash flows are capitalized to property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

**Income Taxes**

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted as at the date of the balance sheet. Accounting for income taxes is a complex process that requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will be due.

**Risk Management Activities**

The Company utilizes various derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

**Purchase Price Allocations**

Purchase prices related to business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. As a result, the purchase price allocation impacts the Company’s reported assets and liabilities and future net earnings due to the impact on future DD&A expense and impairment tests.

The Company has made various assumptions in determining the fair values of the acquired assets and liabilities. The most significant assumptions and judgments relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates (a) crude oil and natural gas reserves, and (b) future prices of crude oil and natural gas. Reserve estimates are based on the work performed by the Company’s internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in “Crude Oil and Natural Gas Reserves”. Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

## Consolidated Balance Sheets

| (millions of Canadian dollars, unaudited) | Note | **Mar 31 2011** | Dec 31 2010 | Jan 1 2010 |
|---|---|---|---|---|
| **ASSETS** | | | | |
| **Current assets** | | | | |
| Cash and cash equivalents | | **$ 50** | $ 22 | $ 13 |
| Accounts receivable | | **1,624** | 1,481 | 1,148 |
| Inventory | | **496** | 477 | 438 |
| Prepaids and other | | **108** | 129 | 146 |
| | | **2,278** | 2,109 | 1,745 |
| **Exploration and evaluation assets** | 5 | **2,400** | 2,402 | 2,293 |
| **Property, plant and equipment** | 6 | **38,775** | 38,429 | 37,018 |
| **Other long-term assets** | 4 | **388** | 14 | 6 |
| | | **$ 43,841** | $ 42,954 | $ 41,062 |
| **LIABILITIES** | | | | |
| **Current liabilities** | | | | |
| Accounts payable | | **$ 453** | $ 274 | $ 240 |
| Accrued liabilities | | **2,269** | 1,735 | 1,430 |
| Current income tax liabilities | | **296** | 430 | 94 |
| Current portion of long-term debt | 7 | **389** | 397 | 400 |
| Current portion of other long-term liabilities | 8 | **917** | 870 | 854 |
| | | **4,324** | 3,706 | 3,018 |
| **Long-term debt** | 7 | **8,079** | 8,088 | 9,259 |
| **Other long-term liabilities** | 8 | **3,018** | 3,004 | 2,485 |
| **Deferred income tax liabilities** | | **7,825** | 7,788 | 7,462 |
| | | **23,246** | 22,586 | 22,224 |
| **SHAREHOLDERS' EQUITY** | | | | |
| **Share capital** | 10 | **3,394** | 3,147 | 2,834 |
| **Retained earnings** | | **17,158** | 17,212 | 15,927 |
| **Accumulated other comprehensive income** | 11 | **43** | 9 | 77 |
| | | **20,595** | 20,368 | 18,838 |
| | | **$ 43,841** | $ 42,954 | $ 41,062 |

*Commitments and contingencies (Note 15)*

Approved by the Board of Directors on May 5, 2011

## Consolidated Statements of Earnings

| (millions of Canadian dollars, except per common share amounts, unaudited) | Note | Three Months Ended Mar 31 2011 | Mar 31 2010 |
|---|---|---|---|
| Product sales | | **$ 3,302** | $ 3,580 |
| Less: royalties | | **(351)** | (353) |
| **Revenue** | | **2,951** | 3,227 |
| **Expenses** | | | |
| Production | | **845** | 894 |
| Transportation and blending | | **621** | 414 |
| Depletion, depreciation and amortization | 6 | **849** | 797 |
| Administration | | **54** | 54 |
| Share-based compensation | 8 | **128** | 29 |
| Asset retirement obligation accretion | 8 | **33** | 30 |
| Interest and other financing costs | | **94** | 109 |
| Risk management activities | 14 | **124** | (171) |
| Foreign exchange gain | | **(67)** | (126) |
| Horizon asset impairment provision | 17 | **396** | – |
| Insurance recovery | 17 | **(396)** | – |
| | | **2,681** | 2,030 |
| **Earnings before taxes** | | **270** | 1,197 |
| Current income tax expense | 9 | **171** | 220 |
| Deferred income tax expense | 9 | **53** | 242 |
| **Net earnings** | | **$ 46** | $ 735 |
| **Net earnings per common share** | | | |
| Basic | 13 | **$ 0.04** | $ 0.68 |
| Diluted | 13 | **$ 0.04** | $ 0.67 |

## Consolidated Statements of Comprehensive Income

| (millions of Canadian dollars, unaudited) | Three Months Ended Mar 31 2011 | Mar 31 2010 |
|---|---|---|
| **Net earnings** | **$ 46** | $ 735 |
| **Net change in derivative financial instruments designated as cash flow hedges** | | |
| Unrealized income (loss) during the period, net of taxes of $3 million (2010 – $2 million) | **18** | (12) |
| Reclassification to net earnings, net of taxes of $4 million (2010 – $nil) | **11** | – |
| | **29** | (12) |
| **Foreign currency translation adjustment** | | |
| Translation of net investment | **5** | (32) |
| **Other comprehensive income (loss), net of taxes** | **34** | (44) |
| **Comprehensive income** | **$ 80** | $ 691 |

**Consolidated Statements of Changes in Equity**

| (millions of Canadian dollars, unaudited) | Note | Three Months Ended Mar 31 2011 | Mar 31 2010 |
|---|---|---|---|
| **Share capital** | 10 | | |
| Balance – beginning of period | | **$ 3,147** | $ 2,834 |
| Issued upon exercise of stock options | | **162** | 40 |
| Previously recognized liability on stock options exercised for common shares | | **85** | 65 |
| Balance – end of period | | **3,394** | 2,939 |
| **Retained earnings** | | | |
| Balance – beginning of period | | **17,212** | 15,927 |
| Net earnings | | **46** | 735 |
| Dividends on common shares | 10 | **(100)** | (81) |
| Balance – end of period | | **17,158** | 16,581 |
| **Accumulated other comprehensive income** | 11 | | |
| Balance – beginning of period | | **9** | 77 |
| Other comprehensive income (loss), net of taxes | | **34** | (44) |
| Balance – end of period | | **43** | 33 |
| **Shareholders' equity** | | **$ 20,595** | $ 19,553 |

## Consolidated Statements of Cash Flows

| (millions of Canadian dollars, unaudited) | Note | Three Months Ended Mar 31 2011 | Mar 31 2010 |
|---|---|---|---|
| **Operating activities** | | | |
| Net earnings | | **$ 46** | $ 735 |
| Non-cash items | | | |
| Depletion, depreciation and amortization | | **849** | 797 |
| Share-based compensation | | **128** | 29 |
| Asset retirement obligation accretion | | **33** | 30 |
| Unrealized risk management loss (gain) | | **54** | (210) |
| Unrealized foreign exchange gain | | **(89)** | (116) |
| Deferred income tax expense | | **53** | 242 |
| Horizon asset impairment provision | 17 | **396** | – |
| Insurance recovery | 17 | **(396)** | – |
| Other | | **(29)** | (27) |
| Abandonment expenditures | | **(64)** | (39) |
| Net change in non-cash working capital | | **264** | (109) |
| | | **1,245** | 1,332 |
| **Financing activities** | | | |
| Issue (repayment) of bank credit facilities, net | | **128** | (528) |
| Issue of common shares on exercise of stock options | | **162** | 40 |
| Dividends on common shares | | **(82)** | (57) |
| Net change in non-cash working capital | | **–** | (4) |
| | | **208** | (549) |
| **Investing activities** | | | |
| Expenditures on exploration and evaluation assets and property, plant and equipment | | **(1,630)** | (1,037) |
| Investment in other assets | | **(346)** | – |
| Net change in non-cash working capital | | **551** | 262 |
| | | **(1,425)** | (775) |
| **Increase in cash and cash equivalents** | | **28** | 8 |
| **Cash and cash equivalents – beginning of period** | | **22** | 13 |
| **Cash and cash equivalents – end of period** | | **$ 50** | $ 21 |
| **Interest paid** | | **$ 147** | $ 152 |
| **Income taxes paid** | | **$ 282** | $ 46 |

## 1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

Also within Western Canada, the Company maintains certain midstream activities that include pipeline operations and an electricity co-generation system.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2500, 855-2 Street S.W., Calgary, Alberta.

In 2010, the Canadian Institute of Chartered Accountants ("CICA") Handbook was revised to incorporate International Financial Reporting Standards ("IFRS") and require publicly accountable enterprises to apply IFRS effective for years beginning on or after January 1, 2011. The 2011 fiscal year is the first year in which the Company has prepared its consolidated financial statements in accordance with IFRS as issued by the International Accounting Standards Board. These interim consolidated financial statements have been prepared in accordance with IFRS applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34, "Interim Financial Reporting" and IFRS 1, "First-time Adoption of International Financial Reporting Standards". Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed.

The accounting policies adopted by the Company under IFRS are set out below and are based on IFRS issued and outstanding as at May 5, 2011. Subject to certain transition elections disclosed in Note 18, the Company 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. Any subsequent changes to IFRS that are given effect in the Company's annual consolidated financial statements for the year ending December 31, 2011 may result in restatement of these interim consolidated financial statements, including the transition adjustments recognized on transition to IFRS.

Comparative information for 2010 has been restated from Canadian Generally Accepted Accounting Principles ("Canadian GAAP") to comply with IFRS. In these consolidated financial statements, Canadian GAAP refers to Canadian GAAP before the adoption of IFRS. Note 18 discloses the impact of the transition to IFRS on the Company's reported financial position, earnings and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Company's Canadian GAAP consolidated financial statements for the year ended December 31, 2010.

### (A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and partnerships. Certain of the Company's activities are conducted through joint ventures where the Company has a direct ownership interest in jointly controlled assets. The income, expenses, assets and liabilities related to the jointly controlled assets are included in the consolidated financial statements in proportion to the Company's interest.

### (B) CASH AND CASH EQUIVALENTS

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with an original term to maturity at purchase of three months or less are reported as cash equivalents in the consolidated balance sheets.

### (C) INVENTORIES

Inventories are primarily comprised of product inventory and materials and supplies. Product inventory includes crude oil held for sale, pipeline linefill and crude oil stored in floating production, storage and offloading vessels. Inventories are carried at the lower of cost and net realizable value. Cost consists of purchase costs, direct production costs, direct overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value is determined by reference to forward prices as at the date of the consolidated balance sheets.

### (D) EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves. The Company accounts for E&E costs in accordance with the requirements of IFRS 6 "Exploration for and Evaluation of Mineral Resources".

E&E costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and the costs associated with retiring the assets. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area, which are recognized immediately in net earnings.

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved reserves are determined to exist.

E&E assets are also tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated reserves, increases in estimated future exploration or development expenditures, and significant adverse changes in the applicable legislative or regulatory frameworks.

### (E) PROPERTY, PLANT AND EQUIPMENT

#### Exploration and Production

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. When significant components of an item of property, plant and equipment, including crude oil and natural gas interests, have different useful lives, they are accounted for separately.

The deemed cost of an asset comprises its purchase price, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included in property, plant and equipment.

The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, was determined as described in Note 18.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

#### Oil Sands Mining and Upgrading

Horizon is comprised of both mining and upgrading operations and accordingly, capitalized costs are reported in a separate operating segment from the Company's Canadian exploration and production costs. Capitalized mining activity costs include property acquisition, construction and development costs, the estimate of any asset retirement costs, and applicable borrowing costs. Construction and development costs are capitalized separately to each phase of Horizon. The construction and development of a particular phase of Horizon is considered complete once the phase is available for its intended use.

Mine-related costs and costs of the upgrader and related infrastructure located on the Horizon site are amortized on the unit-of-production method based on Horizon proved reserves or productive capacity. Moveable mine-related equipment is depreciated on a straight-line basis over its estimated useful life.

**Midstream and head office**

The Company capitalizes all costs that expand the capacity or extend the useful life of the assets. Midstream assets are depreciated on a straight-line basis over their estimated lives. Head office assets are amortized on a declining balance basis.

**Useful lives**

The expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in useful lives accounted for prospectively.

**Derecognition**

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is recognized in net earnings.

**Major maintenance expenditure**

Inspection costs associated with major maintenance turnarounds are capitalized and amortized over the period to the next major maintenance turnaround. All other maintenance costs are expensed as incurred.

**Impairment**

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves, or increases in estimated future development expenditures. If any such indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGU's, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, had no impairment loss been recognized for the asset in prior periods. Such reversal is recognized in net earnings. After a reversal, the depletion charge is adjusted in future periods to allocate the asset's revised carrying amount over its remaining useful life.

## (F) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during the initial development of a mine are capitalized to property, plant and equipment. Overburden removal costs incurred during the production of a mine are included in the cost of inventory, unless the overburden removal activity has resulted in a probable inflow of future economic benefits to the Company, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are amortized over the life of the mining reserves that directly benefit from the overburden removal activity.

## (G) CAPITALIZED BORROWING COSTS

Borrowing costs attributable to the acquisition, construction or production of qualifying assets are capitalized to the cost of those assets until such time as the assets are substantially available for their intended use. Qualifying assets are comprised of those significant assets that require a period greater than one year to be available for their intended use. All other borrowing costs are recognized in net earnings.

## (H) LEASES

Finance leases, which transfer to the Company substantially all of the risks and rewards incidental to ownership of the leased item, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Operating lease payments are recognized in production expense in the statements of earnings over the lease term.

## (I) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on all of its property, plant and equipment based on current legislation and industry operating practices. Provisions for asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Provisions are measured at the present value of management's best estimate of expenditures required to settle the present obligation at the date of the balance sheet. Subsequent to the initial measurement, the obligation is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas increases/decreases due to changes in interest rates and the estimated future cash flows are capitalized to property, plant, and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

## (J) FOREIGN CURRENCY TRANSLATION

(i) Functional and presentation currency

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

The assets and liabilities of subsidiaries that have a functional currency different from that of the Company are translated into Canadian dollars at the closing rate at the date of the balance sheet, and income and expenses are translated at the average rate for the period. The changes are recognized in other comprehensive income as cumulative foreign currency translation adjustments.

When the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in other comprehensive income related to the foreign operation are recognized in net earnings.

(ii) Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at year-end exchange rates of monetary assets and liabilities denominated in currencies other than the functional currency of the Company are recognized in net earnings.

### (K) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the sale of crude oil and natural gas is recognized when title passes to the customer, delivery has taken place and collection is reasonably assured. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Revenue represents the Company's share net of royalty payments to governments and other mineral interest owners. Related costs of goods sold are comprised of production, transportation and blending, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the statements of net earnings.

### (L) PRODUCTION SHARING CONTRACTS

Production generated from Offshore Africa is currently shared under the terms of various Production Sharing Contracts ("PSCs"). Product sales are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective Government State Oil Companies (the "Governments"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the PSCs.

### (M) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases.

Deferred income tax assets and liabilities are calculated using the substantively enacted rates that are expected to apply when the asset or liability is recovered. Deferred income tax assets or liabilities are not recognized when they arise on the initial recognition of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit. Deferred income tax assets or liabilities are also not recognized on possible future distributions of retained earnings of subsidiaries where the timing of the distribution can be controlled by the Company and it is probable that a distribution will not be made in the foreseeable future, or when distributions can be made without incurring income taxes.

Deferred income tax assets for deductible temporary differences and tax loss carry forwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carry forwards can be utilized. The carrying amount of deferred income tax assets is reviewed at each reporting date, and is reduced if it is no longer probable that sufficient future taxable profits will be available against which the temporary differences or tax loss carry forwards can be utilized.

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date. Income taxes are recognized in net earnings or other comprehensive income, consistent with the items to which they relate.

Taxable income arising from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in periods subsequent to the current reporting period. Accordingly, North America current and deferred income taxes have been provided on the basis of this corporate structure.

### (N) SHARE-BASED COMPENSATION

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are re-measured for subsequent changes in the fair value of the liability. Fair value is determined by using the Black-Scholes valuation model. Expected volatility is estimated based on historic results. Re-measurements are recognized in each reporting period. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by the employee and any previously recognized liability associated with the stock options are recorded as share capital.

### (O) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: fair value through profit or loss; held-to-maturity investments; loans and receivables; and financial liabilities measured at amortized cost. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash, cash equivalents, and accounts receivable are classified as loans and receivables. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as other financial liabilities measured at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

Financial assets and liabilities are also categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs in respect of financial instruments at fair value through profit or loss are recognized immediately in net earnings. Transaction costs in respect of other financial instruments are included in the initial measurement of the financial instrument.

#### Impairment of financial assets

At each reporting date, the Company assesses whether there is objective evidence that a financial asset is impaired. If such evidence exists, an impairment loss is recognized.

Impairment losses on financial assets carried at amortized cost including loans and receivables are calculated as the difference between the amortized cost of the loan or receivable and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate. Impairment losses on financial assets carried at amortized cost are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

### (P) RISK MANAGEMENT ACTIVITIES

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value as determined based on appropriate external valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. The Company's own credit risk is not included in the carrying amount of the risk management liability.

The Company documents all derivative financial instruments that are formally designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales and purchases of crude oil and natural gas in order to protect cash flow for capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in net earnings in the same period or periods in which the commodity is sold. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in net earnings.

The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in net earnings immediately.

Cross currency swap contracts are periodically used to manage currency exposure on US dollar denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges related to the notional principal amounts are included in foreign exchange in net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in net earnings. Changes in the fair value of non-designated cross currency swap contracts are included in risk management activities in net earnings.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged items are recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in net earnings immediately.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is derecognized on the consolidated balance sheets and the related long-term debt hedged is no longer revalued for subsequent changes in fair value. The fair value adjustment on the long-term debt at the date of termination of the interest rate swap is amortized to interest expense over the remaining term of the long-term debt.

Foreign currency forward contracts are periodically used to manage foreign currency cash requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange loss (gain) when realized. Changes in the fair value of foreign currency forward contracts not included as hedges are included in risk management activities in net earnings immediately.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract.

### (Q) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses on the net investment in self-sustaining foreign operations. Other comprehensive income is shown net of related income taxes.

### (R) PER COMMON SHARE AMOUNTS

The Company calculates basic earnings per share by dividing net earnings by the weighted average number of common shares outstanding during the period. As the Company's stock option plan allows for the settlement of stock options in either cash or shares at the option of the holder, diluted earnings per share is calculated using the more dilutive of cash settlement or share settlement under the treasury stock method.

### (S) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from proceeds. When common shares are repurchased, the amount of the consideration paid, net of the excess of the purchase price of common shares over their average carrying value, is recognized as a reduction of share capital. The excess of the purchase price over average carrying value is recognized as a reduction of retained earnings. Repurchased shares are cancelled upon purchase.

### (T) DIVIDENDS

Dividends on common shares are recognized in the Company's financial statements in the period in which the dividends are approved by the Board of Directors.

## 2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The Company is required to adopt IFRS 9, "Financial Instruments", effective January 1, 2013, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, "Financial Instruments - Recognition and Measurement". The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

## 3. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

The Company has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

(a) Estimates of crude oil and natural gas reserves

Purchase price allocations, depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserve estimates 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 Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices.

(b) Asset retirement obligations

The calculation of asset retirement obligations includes estimates of the future costs and the timing of the cash flows to settle the liability, the discount rate used in reflecting the passage of time, and future inflation rates.

(c) Income taxes

The Company is subject to income taxes in numerous jurisdictions. Accounting for income taxes is a complex process that requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgments with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will be due.

(d) Fair value of derivatives and other financial instruments

The fair value of financial instruments that are not traded in an active market is determined using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates.

(e) Purchase price allocations

Purchase prices related to business combinations and asset acquisitions are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation, and amortization expense and impairment tests.

(f) Share-based compensation

The Company has made various assumptions in estimating the fair values of the common stock options granted including expected volatility, expected exercise behavior and future forfeiture rates. At each period end, options outstanding are remeasured for changes in the fair value of the liability.

(g) Identification of cash generating units

Cash generating units 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 Company's operations.

## 4. OTHER LONG-TERM ASSETS

| | Mar 31 2011 | Dec 31 2010 | Jan 1 2010 |
|---|---|---|---|
| Investment in North West Redwater Partnership | **$ 346** | $ – | $ – |
| Other | **42** | 14 | 6 |
| | **$ 388** | $ 14 | $ 6 |

Other long-term assets include a $346 million equity investment in the 50% owned North West Redwater Partnership ("Redwater"). Redwater has entered into an agreement to construct and operate a 50,000 bbl/d bitumen refinery, which targets to process bitumen under a 30 year fee-for-service contract. Project development is dependent upon completion of detailed engineering and final project sanction by both Redwater and the Government of Alberta.

## 5. EXPLORATION AND EVALUATION ASSETS

| | **Exploration and Production** | | | | **Oil Sands Mining and Upgrading** | **Total** |
|---|---|---|---|---|---|---|
| | **North America** | **North Sea** | **Offshore Africa** | **Other** | | |
| **Cost** | | | | | | |
| At January 1, 2010 | $ 2,102 | $ – | $ 191 | $ – | $ – | $ 2,293 |
| Acquisitions | 522 | – | – | – | – | 522 |
| Additions | 41 | 6 | 3 | – | – | 50 |
| Transfer to property, plant and equipment | (299) | – | (154) | – | – | (453) |
| Foreign exchange adjustments | – | (1) | (9) | – | – | (10) |
| At December 31, 2010 | 2,366 | 5 | 31 | – | – | 2,402 |
| Acquisitions | **–** | **–** | **–** | **–** | **–** | **–** |
| Additions | **74** | **–** | **–** | **–** | **–** | **74** |
| Transfer to property, plant and equipment | **(72)** | **(4)** | **–** | **–** | **–** | **(76)** |
| Foreign exchange adjustments | **–** | **–** | **–** | **–** | **–** | **–** |
| At March 31, 2011 | **$ 2,368** | **$ 1** | **$ 31** | **$ –** | **$ –** | **$ 2,400** |

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## 6. PROPERTY, PLANT AND EQUIPMENT

| | Exploration and Production | | | | Oil Sands Mining and Upgrading | Midstream | Head office | Total |
|---|---|---|---|---|---|---|---|---|
| | North America | North Sea | Offshore Africa | Other | | | | |
| **Cost** | | | | | | | | |
| At January 1, 2010 | $ 36,159 | $ 3,866 | $ 2,666 | $ – | $ 13,758 | $ 284 | $ 214 | $ 56,947 |
| Additions | 4,403 | 190 | 254 | – | 411 | 7 | 18 | 5,283 |
| Transfer from E&E assets | 299 | – | 154 | – | – | – | – | 453 |
| Disposals/ derecognition | – | (5) | – | – | – | – | (11) | (16) |
| Foreign exchange adjustments and other | – | (238) | (146) | – | – | – | (5) | (389) |
| At December 31, 2010 | 40,861 | 3,813 | 2,928 | – | 14,169 | 291 | 216 | 62,278 |
| Additions | **1,161** | **41** | **33** | **–** | **320** | **3** | **6** | **1,564** |
| Transfer from E&E assets | **72** | **4** | **–** | **–** | **–** | **–** | **–** | **76** |
| Disposals/ derecognition [1] | **–** | **–** | **–** | **–** | **(411)** | **–** | **–** | **(411)** |
| Foreign exchange adjustments and other | **–** | **(88)** | **(67)** | **–** | **–** | **–** | **–** | **(155)** |
| At March 31, 2011 | **$ 42,094** | **$ 3,770** | **$ 2,894** | **$ –** | **$ 14,078** | **$ 294** | **$ 222** | **$ 63,352** |
| **Accumulated depletion and depreciation** | | | | | | | | |
| At January 1, 2010 | $ 16,427 | $ 2,054 | $ 1,008 | $ – | $ 207 | $ 81 | $ 152 | $ 19,929 |
| Expense | 2,473 | 295 | 298 | – | 396 | 8 | 13 | 3,483 |
| Product inventory costing | (5) | (5) | 21 | – | 4 | – | – | 15 |
| Impairment [2] | – | – | 637 | – | – | – | – | 637 |
| Disposals/ derecognition | – | (5) | – | – | – | – | (11) | (16) |
| Foreign exchange adjustments and other | – | (134) | (60) | – | – | – | (5) | (199) |
| At December 31, 2010 | 18,895 | 2,205 | 1,904 | – | 607 | 89 | 149 | 23,849 |
| Expense | **699** | **68** | **53** | **–** | **23** | **2** | **4** | **849** |
| Product inventory costing | **(9)** | **8** | **(15)** | **–** | **3** | **–** | **–** | **(13)** |
| Impairment [1] | **–** | **–** | **–** | **–** | **396** | **–** | **–** | **396** |
| Disposals/ derecognition [1] | **–** | **–** | **–** | **–** | **(411)** | **–** | **–** | **(411)** |
| Foreign exchange adjustments and other | **–** | **(51)** | **(42)** | **–** | **–** | **–** | **–** | **(93)** |
| At March 31, 2011 | **$ 19,585** | **$ 2,230** | **$ 1,900** | **$ –** | **$ 618** | **$ 91** | **$ 153** | **$ 24,577** |
| **Net book amount** | | | | | | | | |
| **- at March 31, 2011** | **$ 22,509** | **$ 1,540** | **$ 994** | **$ –** | **$ 13,460** | **$ 203** | **$ 69** | **$ 38,775** |
| - at December 31, 2010 | $ 21,966 | $ 1,608 | $ 1,024 | $ – | $ 13,562 | $ 202 | $ 67 | $ 38,429 |
| - at January 1, 2010 | $ 19,732 | $ 1,812 | $ 1,658 | $ – | $ 13,551 | $ 203 | $ 62 | $ 37,018 |

*(1) During the first quarter of 2011, the Company derecognized certain property, plant and equipment related to the coker fire incident at Horizon in the amount of $411 million. For additional information, refer to Note 17.*

*(2) During 2010, the Company recognized a $637 million impairment relating to Gabon, Offshore Africa which was included in depletion, depreciation and amortization expense. The impairment was based on the difference between the December 31, 2010 net book value of the assets and their recoverable amounts. The recoverable amounts were determined using fair value less costs to sell based on discounted future cash flows of proved and probable reserves using forecast prices and costs.*

| **Development projects not subject to depletion** | | |
|---|---|---|
| At March 31, 2011 | $ | 1,184 |
| At December 31, 2010 | $ | 934 |
| At January 1, 2010 | $ | 1,270 |

The Company acquired a number of producing crude oil and natural gas assets in the Exploration and Production segment for a total consideration of $224 million during the period ended March 31, 2011 (year ended December 31, 2010 – $1,482 million).

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once construction is substantially complete. For the three months ended March 31, 2011, pre-tax interest of $11 million was capitalized to property, plant, and equipment (March 31, 2010 – $7 million) using a capitalization rate of 4.7% (March 31, 2010 – 4.8%).

## 7. LONG-TERM DEBT

| | **Mar 31 2011** | Dec 31 2010 | Jan 1 2010 |
|---|---|---|---|
| **Canadian dollar denominated debt** | | | |
| Bank credit facilities (banker's acceptances) | **$ 1,564** | $ 1,436 | $ 1,897 |
| Medium-term notes | **800** | 800 | 1,200 |
| | **2,364** | 2,236 | 3,097 |
| **US dollar denominated debt** | | | |
| US dollar debt securities (US$6,300 million) | **6,123** | 6,266 | 6,594 |
| Less – original issue discount on US dollar debt securities [1] | **(20)** | (20) | (22) |
| | **6,103** | 6,246 | 6,572 |
| Fair value impact of interest rate swaps on US dollar debt securities [2] | **44** | 47 | 39 |
| | **6,147** | 6,293 | 6,611 |
| Long-term debt before transaction costs | **8,511** | 8,529 | 9,708 |
| Less: transaction costs [1] [3] | **(43)** | (44) | (49) |
| | **8,468** | 8,485 | 9,659 |
| Less: current portion [1] | **389** | 397 | 400 |
| | **$ 8,079** | $ 8,088 | $ 9,259 |

*(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying value of the outstanding debt.*

*(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $44 million (December 2010 – $47 million, January 2010 – $39 million) to reflect the fair value impact of hedge accounting.*

*(3) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.*

### Bank Credit Facilities

As at March 31, 2011, the Company had in place unsecured bank credit facilities of $3,953 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities can be made by way of Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

The Company's weighted average interest rate on bank credit facilities outstanding as at March 31, 2011, was 1.4% (March 31, 2010 – 0.7%), and on long-term debt outstanding for the three months ended March 31, 2011 was 4.8% (March 31. 2010 – 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $484 million, including $180 million related to Horizon and $171 million related to North Sea operations, were outstanding at March 31, 2011. Subsequent to March 31, 2011 the financial guarantee related to Horizon was reduced to $163 million.

### Medium-Term Notes

During 2009, the Company filed a base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

### US Dollar Debt Securities

During 2009, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

## 8. OTHER LONG-TERM LIABILITIES

| | **Mar 31 2011** | Dec 31 2010 | Jan 1 2010 |
|---|---|---|---|
| Asset retirement obligations | **$ 2,577** | $ 2,624 | $ 2,214 |
| Share-based compensation | **707** | 663 | 622 |
| Risk management (Note 14) | **552** | 485 | 325 |
| Other | **99** | 102 | 178 |
| | **3,935** | 3,874 | 3,339 |
| Less: current portion | **917** | 870 | 854 |
| | **$ 3,018** | $ 3,004 | $ 2,485 |

### Asset retirement obligations

The Company's asset retirement obligations will be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.2% (December 31, 2010 – 5.1%; January 1, 2010 – 5.8%). A reconciliation of the discounted asset retirement obligations is as follows:

| | **Mar 31 2011** | Dec 31 2010 |
|---|---|---|
| Balance – beginning of period | **$ 2,624** | $ 2,214 |
| Liabilities incurred | **3** | 12 |
| Liabilities acquired | **–** | 22 |
| Liabilities settled | **(64)** | (179) |
| Asset retirement obligation accretion | **33** | 123 |
| Revision of estimates | **–** | 474 |
| Foreign exchange | **(19)** | (42) |
| Balance – end of period | **$ 2,577** | $ 2,624 |

**Share-based Compensation**

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve–month period if all vested options are surrendered for cash settlement.

| | **Mar 31 2011** | Dec 31 2010 |
|---|---|---|
| Balance – beginning of period | **$ 663** | $ 622 |
| Share-based compensation expense | **128** | 203 |
| Cash payment for options surrendered | **(10)** | (45) |
| Transferred to common shares | **(85)** | (149) |
| Capitalized to Oil Sands Mining and Upgrading | **11** | 32 |
| Balance – end of period | **707** | 663 |
| Less: current portion | **613** | 623 |
| | **$ 94** | $ 40 |

## 9. TAXES

The provision for income tax is as follows:

| | Three Months Ended | |
|---|---|---|
| | **Mar 31 2011** | Mar 31 2010 |
| Current corporate income tax – North America | **$ 91** | $ 129 |
| Current corporate income tax – North Sea | **46** | 53 |
| Current corporate income tax – Offshore Africa | **20** | 6 |
| Current PRT[(1)] expense | **8** | 25 |
| Other taxes | **6** | 7 |
| Current income tax expense | **171** | 220 |
| Deferred corporate income tax expense | **43** | 241 |
| Deferred PRT expense | **10** | 1 |
| Deferred income tax expense | **53** | 242 |
| Income tax expense | **$ 224** | $ 462 |

*(1) Petroleum Revenue Tax*

Taxable income from the Exploration and Production business in Canada is primarily generated through partnerships, with the related income taxes payable in periods subsequent to the current reporting period. North America current and deferred income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

Deferred income tax expense in the first quarter of 2010 included a charge of $132 million related to the enacted changes in Canada to the taxation of stock options surrendered by employees for cash.

During the first quarter of 2011, the UK government substantively enacted an increase to the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $104 million as at March 31, 2011.

## 10. SHARE CAPITAL

### Authorized

200,000 Class 1 preferred shares with a stated value of $10.00 each.

Unlimited number of common shares without par value.

| | Three Months Ended Mar 31, 2011 | | |
|---|---|---|---|
| **Issued**<br>**Common shares** | **Number of shares** (thousands) | | **Amount** |
| Balance – beginning of period | **1,090,848** | **$** | **3,147** |
| Issued upon exercise of stock options | **5,512** | | **162** |
| Previously recognized liability on stock options exercised for common shares | **–** | | **85** |
| Balance – end of period | **1,096,360** | **$** | **3,394** |

### Dividend Policy

On March 1, 2011, the Board of Directors set the regular quarterly dividend at $0.09 per common share (2010 – $0.075 per common share). The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

### Normal Course Issuer Bid

In 2011, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12 month period commencing April 6, 2011 and ending April 5, 2012 up to 27,406,131 common shares or 2.5% of the common shares of the Company outstanding at March 25, 2011. In April 2011, the previous Normal Course Issuer Bid expired. As at May 5, 2011, no common shares had been repurchased for cancellation during 2011.

### Stock Options

The following table summarizes information relating to stock options outstanding at March 31, 2011:

| | Three months ended Mar 31, 2011 | | |
|---|---|---|---|
| | **Stock options** (thousands) | | **Weighted average exercise price** |
| Outstanding – beginning of period | **66,844** | **$** | **33.31** |
| Granted | **1,385** | **$** | **45.05** |
| Surrendered for cash settlement | **(723)** | **$** | **29.94** |
| Exercised for common shares | **(5,512)** | **$** | **29.40** |
| Forfeited | **(968)** | **$** | **34.55** |
| Outstanding – end of period | **61,026** | **$** | **33.95** |
| Exercisable – end of period | **19,031** | **$** | **31.00** |

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

## 11. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income, net of taxes, were as follows:

| | **Mar 31 2011** | Mar 31 2010 |
|---|---|---|
| Derivative financial instruments designated as cash flow hedges | **$ 62** | $ 65 |
| Foreign currency translation adjustment | **(19)** | (32) |
| | **$ 43** | $ 33 |

During the next twelve months, $32 million is expected to be reclassified to net earnings from accumulated other comprehensive income, reducing net earnings.

## 12. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 35% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, and lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At March 31, 2011, the ratio was below the target range at 29%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

| | **Mar 31 2011** | Dec 31 2010 | Jan 1 2010 |
|---|---|---|---|
| Long-term debt (1) | **$ 8,468** | $ 8,485 | $ 9,659 |
| Total shareholders' equity | **$ 20,595** | $ 20,368 | $ 18,838 |
| Debt to book capitalization | **29%** | 29% | 34% |

*(1) Includes the current portion of long-term debt.*

## 13. NET EARNINGS PER COMMON SHARE

| | **Three Months Ended** | |
|---|---|---|
| | **Mar 31 2011** | Mar 31 2010 |
| Weighted average common shares outstanding – basic (thousands of shares) | **1,093,685** | 1,085,590 |
| Effect of dilutive stock options | **11,992** | 8,432 |
| Weighted average common shares outstanding – diluted (thousands of shares) | **1,105,677** | 1,094,022 |
| Net earnings | **$ 46** | $ 735 |
| Net earnings per common share – basic | **$ 0.04** | $ 0.68 |
| – diluted | **$ 0.04** | $ 0.67 |

## 14. FINANCIAL INSTRUMENTS

The carrying values of the Company's financial instruments by category were as follows:

| | Mar 31, 2011 | | | | |
|---|---|---|---|---|---|
| **Asset (liability)** | **Loans and receivables at amortized cost** | **Fair value through profit or loss** | **Derivatives used for hedging** | **Financial liabilities at amortized cost** | **Total** |
| Accounts receivable | **$ 1,624** | **$ –** | **$ –** | **$ –** | **$ 1,624** |
| Accounts payable | **–** | **–** | **–** | **(453)** | **(453)** |
| Accrued liabilities | **–** | **–** | **–** | **(2,269)** | **(2,269)** |
| Other long-term liabilities | **–** | **(222)** | **(330)** | **(90)** | **(642)** |
| Long-term debt [(1)] | **–** | **–** | **–** | **(8,468)** | **(8,468)** |
| | **$ 1,624** | **$ (222)** | **$ (330)** | **$ (11,280)** | **$ (10,208)** |

| | Dec 31, 2010 | | | | |
|---|---|---|---|---|---|
| Asset (liability) | Loans and receivables at amortized cost | Fair value through profit or loss | Derivatives used for hedging | Financial liabilities at amortized cost | Total |
| Accounts receivable | $ 1,481 | $ – | $ – | $ – | $ 1,481 |
| Accounts payable | – | – | – | (274) | (274) |
| Accrued liabilities | – | – | – | (1,735) | (1,735) |
| Other long-term liabilities | – | (167) | (318) | (91) | (576) |
| Long-term debt [(1)] | – | – | – | (8,485) | (8,485) |
| | $ 1,481 | $ (167) | $ (318) | $ (10,585) | $ (9,589) |

| | Jan 1, 2010 | | | | |
|---|---|---|---|---|---|
| Asset (liability) | Loans and receivables at amortized cost | Fair value through profit or loss | Derivatives used for hedging | Financial liabilities at amortized cost | Total |
| Accounts receivable | $ 1,148 | $ – | $ – | $ – | $ 1,148 |
| Accounts payable | – | – | – | (240) | (240) |
| Accrued liabilities | – | – | – | (1,430) | (1,430) |
| Other long-term liabilities | – | (182) | (143) | (167) | (492) |
| Long-term debt [(1)] | – | – | – | (9,659) | (9,659) |
| | $ 1,148 | $ (182) | $ (143) | $ (11,496) | $ (10,673) |

*(1) Includes the current portion of long-term debt.*

The carrying value of the Company's financial instruments approximates their fair value, except for fixed-rate long-term debt as noted below. The fair values of the Company's financial assets and liabilities are outlined below:

| | **Mar 31, 2011** | | |
|---|---|---|---|
| | **Carrying value** | **Fair value** | |
| Asset (liability) [1] | | **Level 1** | **Level 2** |
| Other long-term liabilities | **$ (552)** | **$ –** | **$ (552)** |
| Fixed-rate long-term debt [2] [3] [4] | **(6,904)** | **(7,548)** | **–** |
| | **$ (7,456)** | **$ (7,548)** | **$ (552)** |

| | Dec 31, 2010 | | |
|---|---|---|---|
| | Carrying value | Fair value | |
| Asset (liability) [1] | | Level 1 | Level 2 |
| Other long-term liabilities | $ (485) | $ – | $ (485) |
| Fixed-rate long-term debt [2] [3] [4] | (7,049) | (7,835) | – |
| | $ (7,534) | $ (7,835) | $ (485) |

| | Jan 1, 2010 | | |
|---|---|---|---|
| | Carrying value | Fair value | |
| Asset (liability) [1] | | Level 1 | Level 2 |
| Other long-term liabilities | $ (325) | $ – | $ (325) |
| Fixed-rate long-term debt [2] [3] [4] | (7,762) | (8,212) | – |
| | $ (8,087) | $ (8,212) | $ (325) |

*(1) Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).*

*(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $44 million (December 31, 2010 – $47 million, January 1, 2010 – $39 million) to reflect the fair value impact of hedge accounting.*

*(3) The fair value of fixed-rate long-term debt has been determined based on quoted market prices.*

*(4) Includes the current portion of long-term debt.*

The following provides a summary of the carrying amounts of derivative contracts held and a reconciliation to the Company's consolidated balance sheets.

| Asset (liability) | Mar 31, 2011 | Dec 31, 2010 | Jan 1, 2010 |
|---|---|---|---|
| **Derivatives held for trading** | | | |
| Crude oil price collars | **$ (139)** | $ (64) | $ (256) |
| Crude oil put options | **(75)** | (83) | – |
| Natural gas price collars | **–** | – | 72 |
| Interest rate swaps | **–** | – | 11 |
| Foreign currency forward contracts | **(8)** | (20) | (9) |
| **Cash flow hedges** | | | |
| Natural gas swaps | **(40)** | (49) | – |
| Cross currency swaps | **(290)** | (269) | (158) |
| **Fair value hedges** | | | |
| Interest rate swaps | **–** | – | 15 |
| | **$ (552)** | $ (485) | $ (325) |
| Included within: | | | |
| Current portion of other long-term liabilities | **$ (275)** | $ (222) | $ (182) |
| Other long-term liabilities | **(277)** | (263) | (143) |
| | **$ (552)** | $ (485) | $ (325) |

Ineffectiveness arising from cash flow hedges recognized in the statements of earnings at March 31, 2011 resulted in a loss of $1 million (December 31, 2010 – loss of $1 million).

**Risk Management**

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

The changes in estimated fair values of derivative financial instruments included in the risk management asset (liability) were recognized in the financial statements as follows:

| | **Three Months Ended Mar 31, 2011** | Year Ended Dec 31, 2010 |
|---|---|---|
| **Asset (liability)** | **Risk management mark-to-market** | Risk management mark-to-market |
| Balance – beginning of period | **$ (485)** | $ (325) |
| Net cost of outstanding put options | **78** | 106 |
| Net change in fair value of outstanding derivative financial instruments attributable to: | | |
| Risk management activities | **(54)** | 38 |
| Interest expense | **–** | 16 |
| Foreign exchange | **(48)** | (101) |
| Other comprehensive income | **35** | (58) |
| Settlement of interest rate swaps and other | **–** | (55) |
| | **(474)** | (379) |
| Add: put premium financing obligations [(1)] | **(78)** | (106) |
| Balance – end of period | **(552)** | (485) |
| Less: current portion | **(275)** | (222) |
| | **$ (277)** | $ (263) |

*(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations were reflected in the net risk management asset (liability).*

Net losses (gains) from risk management activities were as follows:

| | **Three Months Ended** | |
|---|---|---|
| | **Mar 31 2011** | Mar 31 2010 |
| Net realized risk management loss | **$ 70** | $ 39 |
| Net unrealized risk management loss (gain) | **54** | (210) |
| | **$ 124** | $ (171) |

**Financial Risk Factors**

**a) Market risk**

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

**Commodity price risk management**

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At March 31, 2011, the Company had the following derivative financial instruments outstanding to manage its commodity price exposures:

i) Sales contracts

| | Remaining term | | | Volume | Weighted average price | | | Index |
|---|---|---|---|---|---|---|---|---|
| **Crude oil** | | | | | | | | |
| Crude oil price collars | Apr 2011 | – | Dec 2011 | 50,000 bbl/d | US$70.00 | – | US $102.23 | WTI |
| Crude oil puts | Apr 2011 | – | Dec 2011 | 100,000 bbl/d | | | US$70.00 | WTI |

The cost of outstanding put options and their respective periods of settlement are as follows:

| | Q2 2011 | Q3 2011 | Q4 2011 |
|---|---|---|---|
| Cost ($ millions) | US$26 | US$27 | US$27 |

ii) Purchase contracts

| | Remaining term | | | Volume | Weighted average fixed rate | Index |
|---|---|---|---|---|---|---|
| **Natural gas** | | | | | | |
| Swaps – floating to fixed | Apr 2011 | – | Dec 2011 | 125,000 GJ/d | C$4.87 | AECO |

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

The natural gas derivative financial instruments designated as hedges at March 31, 2011 were classified as cash flow hedges.

**Interest rate risk management**

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At March 31, 2011 the Company had the following interest rate swap contracts outstanding:

| | Remaining term | | | Amount | Fixed rate | Floating rate |
|---|---|---|---|---|---|---|
| **Interest rate** | | | | | | |
| Swaps – floating to fixed | Apr 2011 | – | Feb 2012 | C$200 | 1.4475% | 3 month CDOR (1) |

*(1)Canadian Dealer Offered Rate*

**Foreign currency exchange rate risk management**

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At March 31, 2011, the Company had the following cross currency swap contracts outstanding:

| | Remaining term | | | Amount | Exchange rate (US$/C$) | Interest rate (US$) | Interest rate (C$) |
|---|---|---|---|---|---|---|---|
| **Cross currency** | | | | | | | |
| Swaps | Apr 2011 | – | Jul 2011 | US$200 | 0.998 | 6.70% | 7.74% |
| | Apr 2011 | – | Aug 2016 | US$250 | 1.116 | 6.00% | 5.40% |
| | Apr 2011 | – | May 2017 | US$1,100 | 1.170 | 5.70% | 5.10% |
| | Apr 2011 | – | Mar 2038 | US$550 | 1.170 | 6.25% | 5.76% |

All cross currency swap derivative financial instruments designated as hedges at March 31, 2011 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at March 31, 2011, the Company had US$1,281 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

**b) Credit Risk**

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

**Counterparty credit risk management**

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At March 31, 2011, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At March 31, 2011, the Company had no net risk management assets with specific counterparties related to derivative financial instruments (December 31, 2010 – $nil, January 1, 2010 – $7 million).

### c) Liquidity Risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates for financial liabilities are as follows:

| | Less than 1 year | 1 to less than 2 years | 2 to less than 5 years | Thereafter |
|---|---|---|---|---|
| Accounts payable | $ 453 | $ – | $ – | $ – |
| Accrued liabilities | $ 2,269 | $ – | $ – | $ – |
| Current Income tax liabilities | $ 296 | $ – | $ – | $ – |
| Risk management | $ 275 | $ 41 | $ 125 | $ 111 |
| Other long-term liabilities | $ 29 | $ 20 | $ 41 | $ – |
| Long-term debt [1] | $ 389 | $ 2,693 | $ 740 | $ 4,665 |

*(1) Long--term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs.*

## 15. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

| | Remaining 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter |
|---|---|---|---|---|---|---|
| Product transportation and pipeline | $ 166 | $ 201 | $ 173 | $ 164 | $ 152 | $ 933 |
| Offshore equipment operating leases | $ 110 | $ 96 | $ 95 | $ 95 | $ 79 | $ 164 |
| Office leases | $ 20 | $ 29 | $ 33 | $ 34 | $ 32 | $ 336 |
| Other | $ 104 | $ 67 | $ 19 | $ 18 | $ 24 | $ 10 |

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

## 16. SEGMENTED INFORMATION

| | Exploration and Production | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **North America** | | **North Sea** | | **Offshore Africa** | | **Total Exploration and Production** | |
| (millions of Canadian dollars, unaudited) | Three Months Ended Mar 31 | | Three Months Ended Mar 31 | | Three Months Ended Mar 31 | | Three Months Ended Mar 31 | |
| | **2011** | 2010 | **2011** | 2010 | **2011** | 2010 | **2011** | 2010 |
| Segmented product sales | **2,706** | 2,486 | **289** | 286 | **215** | 156 | **3,210** | 2,928 |
| Less: royalties | **(326)** | (324) | **(1)** | (1) | **(20)** | (5) | **(347)** | (330) |
| **Segmented revenue** | **2,380** | 2,162 | **288** | 285 | **195** | 151 | **2,863** | 2,598 |
| **Segmented expenses** | | | | | | | | |
| Production | **458** | 427 | **86** | 90 | **42** | 28 | **586** | 545 |
| Transportation and blending | **612** | 407 | **4** | 3 | **1** | – | **617** | 410 |
| Depletion, depreciation and amortization | **703** | 583 | **68** | 76 | **53** | 39 | **824** | 698 |
| Asset retirement obligation accretion | **18** | 13 | **8** | 9 | **2** | 1 | **28** | 23 |
| Realized risk management activities | **70** | 39 | **–** | – | **–** | – | **70** | 39 |
| Horizon asset impairment provision (Note 17) | **–** | – | **–** | – | **–** | – | **–** | – |
| Insurance recovery (Note 17) | **–** | – | **–** | – | **–** | – | **–** | – |
| **Total segmented expenses** | **1,861** | 1,469 | **166** | 178 | **98** | 68 | **2,125** | 1,715 |
| **Segmented earnings (loss) before the following** | **519** | 693 | **122** | 107 | **97** | 83 | **738** | 883 |
| **Non-segmented expenses** | | | | | | | | |
| Administration | | | | | | | | |
| Share-based compensation | | | | | | | | |
| Interest and other financing costs | | | | | | | | |
| Unrealized risk management activities | | | | | | | | |
| Foreign exchange gain | | | | | | | | |
| **Total non-segmented expenses** | | | | | | | | |
| **Earnings before taxes** | | | | | | | | |
| Current income tax expense | | | | | | | | |
| Deferred income tax expense | | | | | | | | |
| **Net earnings** | | | | | | | | |

| (millions of Canadian dollars, unaudited) | Oil Sands Mining and Upgrading<br>Three Months Ended Mar 31 | | Midstream<br>Three Months Ended Mar 31 | | Inter-segment elimination and other<br>Three Months Ended Mar 31 | | Total<br>Three Months Ended Mar 31 | |
|---|---|---|---|---|---|---|---|---|
| | **2011** | 2010 | **2011** | 2010 | **2011** | 2010 | **2011** | 2010 |
| Segmented product sales | **86** | 647 | **22** | 19 | **(16)** | (14) | **3,302** | 3,580 |
| Less: royalties | **(4)** | (23) | **–** | – | **–** | – | **(351)** | (353) |
| **Segmented revenue** | **82** | 624 | **22** | 19 | **(16)** | (14) | **2,951** | 3,227 |
| **Segmented expenses** | | | | | | | | |
| Production | **256** | 346 | **7** | 5 | **(4)** | (2) | **845** | 894 |
| Transportation and blending | **16** | 15 | **–** | – | **(12)** | (11) | **621** | 414 |
| Depletion, depreciation and amortization | **23** | 97 | **2** | 2 | **–** | – | **849** | 797 |
| Asset retirement obligation accretion | **5** | 7 | **–** | – | **–** | – | **33** | 30 |
| Realized risk management activities | **–** | – | **–** | – | **–** | – | **70** | 39 |
| Horizon asset impairment provison (Note 17) | **396** | – | **–** | – | **–** | – | **396** | – |
| Insurance recovery (Note 17) | **(396)** | – | **–** | – | **–** | – | **(396)** | – |
| **Total segmented expenses** | **300** | 465 | **9** | 7 | **(16)** | (13) | **2,418** | 2,174 |
| **Segmented earnings (loss) before the following** | **(218)** | 159 | **13** | 12 | **–** | (1) | **533** | 1,053 |
| **Non-segmented expenses** | | | | | | | | |
| Administration | | | | | | | **54** | 54 |
| Share-based compensation | | | | | | | **128** | 29 |
| Interest and other financing costs | | | | | | | **94** | 109 |
| Unrealized risk management activities | | | | | | | **54** | (210) |
| Foreign exchange gain | | | | | | | **(67)** | (126) |
| **Total non-segmented expenses** | | | | | | | **263** | (144) |
| **Earnings before taxes** | | | | | | | **270** | 1,197 |
| Current income tax expense | | | | | | | **171** | 220 |
| Deferred income tax expense | | | | | | | **53** | 242 |
| **Net earnings** | | | | | | | **46** | 735 |

## Capital Expenditures [1]

| | Three Months Ended | | | | | |
|---|---|---|---|---|---|---|
| | **Mar 31, 2011** | | | Mar 31, 2010 | | |
| | **Net expenditures** | **Non cash and fair value changes[2]** | **Capitalized costs** | Net expenditures | Non cash and fair value changes[2] | Capitalized costs |
| **Exploration and evaluation** | | | | | | |
| Exploration and Production | | | | | | |
| North America | **$ 74** | **$ (72)** | **$ 2** | $ 51 | $ (61) | $ (10) |
| North Sea | **–** | **(4)** | **(4)** | – | – | – |
| | **$ 74** | **$ (76)** | **$ (2)** | $ 51 | $ (61) | $ (10) |
| **Property, plant and equipment** | | | | | | |
| Exploration and Production | | | | | | |
| North America | **$ 1,158** | **$ 75** | **$ 1,233** | $ 758 | $ 64 | $ 822 |
| North Sea | **41** | **4** | **45** | 23 | – | 23 |
| Offshore Africa | **33** | **–** | **33** | 99 | – | 99 |
| | **1,232** | **79** | **1,311** | 880 | 64 | 944 |
| Oil Sands Mining and Upgrading[3][4] | **315** | **(406)** | **(91)** | 102 | – | 102 |
| Midstream | **3** | **–** | **3** | – | – | – |
| Head office | **6** | **–** | **6** | 4 | (11) | (7) |
| | **$ 1,556** | **$ (327)** | **$ 1,229** | $ 986 | $ 53 | $ 1,039 |

*(1) This table provides a reconciliation of capitalized costs and does not include the impact of accumulated depletion, depreciation, and amortization.*

*(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying value and tax value, transfers of exploration and evaluation assets, and other fair value adjustments.*

*(3) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest, share-based compensation, and the impact of intersegment eliminations.*

*(4) During the first quarter of 2011 the Company derecognized certain property, plant and equipment related to the coker fire incident at Horizon in the amount of $411 million. This amount has been included in non cash and fair value changes.*

## Segmented Assets

| | Total assets | |
|---|---|---|
| | **Mar 31 2011** | Dec 31 2010 |
| Exploration and Production | | |
| North America | **$ 26,425** | $ 25,486 |
| North Sea | **1,744** | 1,759 |
| Offshore Africa | **1,142** | 1,263 |
| Other | **28** | 15 |
| Oil Sands Mining and Upgrading | **14,139** | 14,026 |
| Midstream | **294** | 338 |
| Head office | **69** | 67 |
| | **$ 43,841** | $ 42,954 |

## 17. HORIZON ASSET IMPAIRMENT PROVISION AND INSURANCE RECOVERY

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

As at March 31, 2011, the Company recognized a Horizon asset impairment provision of $396 million, net of accumulated depletion and depreciation, related to the property damage resulting from the fire in the primary upgrading coking plant. As the Company believes that its insurance coverage is adequate to mitigate all significant property damage related losses, estimated insurance proceeds receivable of $396 million were also recognized offsetting such property damage. The final Horizon asset impairment provision and related insurance recoveries are subject to revision once restoration of plant operating capacity is completed and final costs are determined. Accordingly, actual results may differ significantly from the amounts currently recognized.

The Company also maintains business interruption coverage, subject to a waiting period, which, commencing in the second quarter, it believes will reduce operating losses related to on-going operations.

## 18. TRANSITION TO IFRS

The effect of the Company's transition to IFRS, described in Note 1, is summarized below:

(i) Transition elections

The Company has applied the following transition exceptions and exemptions to full retrospective application of IFRS as described below:

| | Note |
|---|---|
| Deemed cost of property, plant and equipment | (a) |
| Leases | (b) |
| Share-based compensation | (c) |
| Borrowing costs | (d) |
| Asset retirement obligations | (e) |
| Cumulative translation adjustment | (f) |
| Business combinations | (g) |

(ii) Transition adjustments

The Company has recorded the following transition adjustments upon adoption of IFRS:

| | Note |
|---|---|
| Risk management | (h) |
| Petroleum Revenue Tax | (i) |
| UK deferred income tax liabilities | (j) |
| Reclassification of current portion of deferred income tax | (k) |
| Horizon major maintenance costs | (l) |
| Long-term debt | (m) |

## Reconciliations of the Consolidated Balance Sheets

| (millions of Canadian dollars, unaudited) | | Dec 31 2010 | | | Mar 31 2010 | | | Jan 1 2010 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Note | Canadian GAAP $ | Adj $ | IFRS $ | Canadian GAAP $ | Adj $ | IFRS $ | Canadian GAAP $ | Adj $ | IFRS $ |
| **ASSETS** | | | | | | | | | | |
| **Current assets** | | | | | | | | | | |
| Cash and cash equivalents | | 22 | – | 22 | 21 | – | 21 | 13 | – | 13 |
| Accounts receivable | | 1,481 | – | 1,481 | 1,324 | – | 1,324 | 1,148 | – | 1,148 |
| Inventory | | 481 | (4) | 477 | 450 | (5) | 445 | 438 | – | 438 |
| Prepaids and other | | 129 | – | 129 | 190 | – | 190 | 146 | – | 146 |
| Deferred income tax assets | (k) | 59 | (59) | – | – | – | – | 146 | (146) | – |
| Current portion of other long-term assets | | – | – | – | 22 | – | 22 | – | – | – |
| | | 2,172 | (63) | 2,109 | 2,007 | (5) | 2,002 | 1,891 | (146) | 1,745 |
| **Exploration and evaluation assets** | (a) | – | 2,402 | 2,402 | – | 2,279 | 2,279 | – | 2,293 | 2,293 |
| **Property, plant and equipment** | (a)(c)(e)(l) | 40,472 | (2,043) | 38,429 | 39,252 | (2,107) | 37,145 | 39,115 | (2,097) | 37,018 |
| **Other long-term assets** | | 25 | (11) | 14 | 45 | (12) | 33 | 18 | (12) | 6 |
| | | 42,669 | 285 | 42,954 | 41,304 | 155 | 41,459 | 41,024 | 38 | 41,062 |
| **LIABILITIES** | | | | | | | | | | |
| **Current liabilities** | | | | | | | | | | |
| Accounts payable | | 274 | – | 274 | 269 | – | 269 | 240 | – | 240 |
| Accrued liabilities | | 1,733 | 2 | 1,735 | 1,740 | 2 | 1,742 | 1,428 | 2 | 1,430 |
| Current income tax liabilities | | 430 | – | 430 | 174 | – | 174 | 94 | – | 94 |
| Deferred income tax liabilities | (k) | – | – | – | 5 | (5) | – | – | – | – |
| Current portion of long-term debt | (m) | – | 397 | 397 | – | 400 | 400 | – | 400 | 400 |
| Current portion of other long-term liabilities | (c) | 719 | 151 | 870 | 353 | 231 | 584 | 643 | 211 | 854 |
| | | 3,156 | 550 | 3,706 | 2,541 | 628 | 3,169 | 2,405 | 613 | 3,018 |
| **Long-term debt** | (h)(m) | 8,499 | (411) | 8,088 | 8,939 | (403) | 8,536 | 9,658 | (399) | 9,259 |
| **Other long-term liabilities** | (c)(e)(h) | 2,130 | 874 | 3,004 | 1,878 | 661 | 2,539 | 1,848 | 637 | 2,485 |
| **Deferred income tax liabilities** | (i)(j)(k) | 7,899 | (111) | 7,788 | 7,678 | (16) | 7,662 | 7,687 | (225) | 7,462 |
| | | 21,684 | 902 | 22,586 | 21,036 | 870 | 21,906 | 21,598 | 626 | 22,224 |
| **SHAREHOLDERS' EQUITY** | | | | | | | | | | |
| **Share capital** | | 3,147 | – | 3,147 | 2,939 | – | 2,939 | 2,834 | – | 2,834 |
| **Retained earnings** | | 18,005 | (793) | 17,212 | 17,481 | (900) | 16,581 | 16,696 | (769) | 15,927 |
| **Accumulated other comprehensive (loss) income** | (f)(h) | (167) | 176 | 9 | (152) | 185 | 33 | (104) | 181 | 77 |
| | | 20,985 | (617) | 20,368 | 20,268 | (715) | 19,553 | 19,426 | (588) | 18,838 |
| | | 42,669 | 285 | 42,954 | 41,304 | 155 | 41,459 | 41,024 | 38 | 41,062 |

**Reconciliations of the Consolidated Statements of Earnings**

| (millions of Canadian dollars, except per common share amounts, unaudited) | | Year ended Dec 31 2010 | | | Three months ended Mar 31 2010 | | |
|---|---|---|---|---|---|---|---|
| | Note | Canadian GAAP $ | Adj $ | IFRS $ | Canadian GAAP $ | Adj $ | IFRS $ |
| Product sales | | 14,322 | – | 14,322 | 3,580 | – | 3,580 |
| Less: royalties | | (1,421) | – | (1,421) | (353) | – | (353) |
| **Revenue** | | 12,901 | – | 12,901 | 3,227 | – | 3,227 |
| **Expenses** | | | | | | | |
| Production | (a) | 3,447 | 2 | 3,449 | 894 | – | 894 |
| Transportation and blending | | 1,783 | – | 1,783 | 414 | – | 414 |
| Depletion, depreciation and amortization | (a)(e)(l) | 4,036 | 84 | 4,120 | 771 | 26 | 797 |
| Administration | (a) | 210 | 1 | 211 | 54 | – | 54 |
| Share-based compensation | (c) | 294 | (91) | 203 | (2) | 31 | 29 |
| Asset retirement obligation accretion | (e) | 107 | 16 | 123 | 26 | 4 | 30 |
| Interest and other financing costs | (h) | 449 | (1) | 448 | 111 | (2) | 109 |
| Risk management activities | (h) | (121) | (13) | (134) | (169) | (2) | (171) |
| Foreign exchange (gain) loss | (j) | (182) | 19 | (163) | (160) | 34 | (126) |
| | | 10,023 | 17 | 10,040 | 1,939 | 91 | 2,030 |
| **Earnings before taxes** | | 2,878 | (17) | 2,861 | 1,288 | (91) | 1,197 |
| Taxes other than income tax | | 119 | (119) | – | 39 | (39) | – |
| Current income tax expense | | 698 | 91 | 789 | 188 | 32 | 220 |
| Deferred income tax expense | | 364 | 35 | 399 | 195 | 47 | 242 |
| **Net earnings** | | 1,697 | (24) | 1,673 | 866 | (131) | 735 |
| **Net earnings per common share** | | | | | | | |
| Basic | | 1.56 | (0.02) | 1.54 | 0.80 | (0.12) | 0.68 |
| Diluted | | 1.56 | (0.03) | 1.53 | 0.80 | (0.13) | 0.67 |

**Reconciliations of the Consolidated Statements of Comprehensive Income**

| (millions of Canadian dollars, unaudited) | | Year ended Dec 31, 2010 | | | Three months ended Mar 31, 2010 | | |
|---|---|---|---|---|---|---|---|
| | Note | Canadian GAAP $ | Adj $ | IFRS $ | Canadian GAAP $ | Adj $ | IFRS $ |
| **Net earnings** | | 1,697 | (24) | 1,673 | 866 | (131) | 735 |
| **Net change in derivative financial instruments designated as cash flow hedges** | | | | | | | |
| Unrealized loss during the period | (h) | (35) | (18) | (53) | (6) | (8) | (14) |
| Income tax | | 11 | 2 | 13 | 1 | 1 | 2 |
| Unrealized loss during the period, net of tax | | (24) | (16) | (40) | (5) | (7) | (12) |
| Reclassification to net earnings | | (5) | – | (5) | – | – | – |
| Income tax | | 1 | – | 1 | – | – | – |
| Reclassification to net earnings, net of taxes | | (4) | – | (4) | – | – | – |
| | | (28) | (16) | (44) | (5) | (7) | (12) |
| **Foreign currency translation adjustment** | | | | | | | |
| Translation of net investment | | (35) | 11 | (24) | (43) | 11 | (32) |
| **Other comprehensive (loss) income, net of taxes** | | (63) | (5) | (68) | (48) | 4 | (44) |
| **Comprehensive income** | | 1,634 | (29) | 1,605 | 818 | (127) | 691 |

**Notes:**

(a) Deemed cost of property, plant and equipment

In accordance with IFRS transitional provisions, the Company elected to use the deemed cost of property, plant and equipment for its exploration and production assets, which allows the Company to measure its exploration and evaluation assets at the amounts capitalized under Canadian GAAP at the date of transition to IFRS. Additionally, under the transitional provision, the Company elected to allocate the carrying value of property, plant and equipment in the development or production phases under Canadian GAAP to IFRS applicable assets pro rata using reserve values as at January 1, 2010, subject to impairment tests. The impairment tests compared the carrying value of the assets to their recoverable amounts. The recoverable amount is the higher of fair value less costs to sell or value in use. The impairment tests conducted by the Company resulted in a reduction to the carrying values of Offshore Africa property, plant and equipment at the date of transition of $62 million. At January 1, 2010, retained earnings were reduced by $53 million, net of income taxes of $9 million.

For the year ended December 31, 2010, net earnings decreased by $119 million, net of taxes of $27 million, to reflect the impact of higher depletion charges, partially offset by $78 million, net of taxes of $11 million, to reflect the impact of a lower impairment charge on the Gabon CGU. For the three months ended March 31, 2010, net earnings decreased by $16 million, net of taxes of $3 million, to reflect the impact of higher depletion charges.

(b) Leases

The Company elected under IFRS 1 not to reassess whether an arrangement contains a lease under IFRIC 4 for contracts that were assessed under Canadian GAAP. Arrangements entered into before the effective date of Canadian GAAP EIC 150 that have not subsequently been assessed under EIC 150, were assessed under IFRIC 4, and no additional leases were identified.

(c) Share-based compensation

The Company has granted share-based compensation that may be settled in either cash or shares at the holder's option to all employees. The Company accounted for these share-based payment arrangements by reference to their intrinsic value under Canadian GAAP. Under IFRS the related liability has been adjusted to reflect the fair value of the outstanding share-based compensation. The Company elected to use the IFRS 1 exemption to not retrospectively restate share-based payment transactions that were settled before the date of transition to IFRS. This adjustment increased the share-based compensation liability by $230 million (December 31, 2010 – $147 million; March 31, 2010 – $265 million). Included in this amount is $11 million (December 31, 2010 – $19 million; March 31, 2010 – $15 million) capitalized to Oil Sands Mining and Upgrading. At January 1, 2010, retained earnings were reduced by $170 million, net of income taxes of $49 million.

For the year ended December 31, 2010, net earnings increased by $91 million and for the three months ended March 31, 2010, net earnings decreased by $31 million to reflect differences in share-based compensation expense. In addition, during the first quarter of 2010, deferred income tax expense included an additional charge of $49 million related to the change to the taxation of stock options surrendered by employees for cash.

(d) Borrowing costs

Under Canadian GAAP the Company was not required to capitalize all borrowing costs in respect of constructed assets. At the date of transition, the Company elected to capitalize borrowing costs in respect of all qualifying assets effective January 1, 2010.

(e) Asset retirement obligations

In accordance with IFRS transitional provisions for assets described in (a) above, the Company remeasured the liability associated with asset retirement obligation activities for the North America, North Sea and Offshore Africa Exploration and Production segments at the date of transition, resulting in an increase in asset retirement obligations of $338 million. At January 1, 2010, retained earnings were reduced by $210 million, net of income taxes of $128 million.

In addition, the Company remeasured the liability related to asset retirement obligation activities in the Oil Sands Mining and Upgrading segment at the date of transition. These assets were not subject to the election in (a) above and accordingly, the difference in the liability between Canadian GAAP and IFRS of $266 million was recognized in property, plant and equipment in accordance with IFRS transitional provisions. Additional accumulated depletion of $2 million was recognized in retained earnings.

The difference between Canadian GAAP and IFRS asset retirement obligations related primarily to discount rates.

As at December 31, 2010, an additional liability of $234 million was recognized in property, plant and equipment. For the year ended December 31, 2010, net earnings decreased by $15 million, net of taxes of $6 million, and for the three months ended March 31, 2010, net earnings decreased by $3 million, net of taxes of $2 million, to reflect the impact of higher depletion and accretion charges.

(f) Cumulative translation adjustment

In accordance with IFRS transitional provisions, the Company elected to reset the cumulative translation adjustment account, which includes gains and losses arising from the translation of foreign operations, to $nil at the date of transition to IFRS. Accordingly, accumulated other comprehensive income increased by $180 million and retained earnings were reduced by $180 million.

(g) Business combinations

In accordance with IFRS transitional provisions, the Company elected to apply IFRS relating to business combinations prospectively from January 1, 2010. As such, Canadian GAAP balances relating to business combinations entered into before that date have been carried forward without adjustment.

(h) Risk management

Under Canadian GAAP, the Company was required to adjust the carrying amount of the liability for risk management derivative financial instruments by the Company's own credit risk. Under IFRS, this adjustment is not required. The reversal of the credit risk adjustment for IFRS on January 1, 2010 resulted in an increase in the carrying amount of the risk management liability of $16 million (December 31, 2010 – $34 million; March 31, 2010 – $24 million) and an increase in accumulated comprehensive income of $1 million (December 31, 2010 – decrease of $15 million; March 31, 2010 – decrease of $6 million). At January 1, 2010, retained earnings were reduced by $13 million, net of income taxes of $5 million. Further, differences in applying fair value hedge accounting between Canadian GAAP and IFRS resulted in an increase to the carrying value of hedged long-term debt by $1 million (December 31, 2010 – decrease of $14 million; March 31, 2010 – decrease of $3 million).

For the year ended December 31, 2010, net earnings increased by $10 million, net of income taxes of $4 million and other comprehensive income decreased by $16 million, net of income taxes of $2 million. For the three months ended March 31, 2010, net earnings increased by $4 million, net of income taxes of $nil, and other comprehensive income decreased by $7 million, net of income taxes of $1 million.

(i) Petroleum Revenue Tax

Under Canadian GAAP, the Company calculated its deferred PRT liability using the life-of-field method. Under IFRS, the Company calculates its deferred PRT liability based on temporary differences arising between the tax base of assets and liabilities of PRT paying fields and their carrying amounts in the consolidated balance sheets. As a result of this adjustment, the deferred income tax liability was increased by $116 million ($58 million after-tax) at January 1, 2010 (December 31, 2010 – $80 million, $40 million after-tax; March 31, 2010 – $110 million, $55 million after-tax). At January 1, 2010, retained earnings were reduced by $58 million.

For the year ended December 31, 2010, net earnings increased by $18 million, net of taxes of $18 million and for the three months ended March 31, 2010, net earnings increased by $3 million, net of taxes of $3 million, to reflect the impact of lower PRT charges.

(j) UK deferred income tax liabilities

Under Canadian GAAP, the Company calculated the future income tax liabilities of its UK subsidiaries in UK pounds sterling, and converted the resultant liability to its US dollar functional currency. Under IFRS, the Company calculates its UK-based deferred income tax liabilities directly in the functional US dollar currency. This adjustment resulted in an increase in the deferred income tax liability of $61 million at January 1, 2010 (December 31, 2010 – $80 million; March 31, 2010 – $95 million). At January 1, 2010, retained earnings were reduced by $61 million.

For the year ended December 31, 2010, net earnings decreased by $19 million, and for the three months ended March 31, 2010, net earnings decreased by $34 million.

(k) Reclassification of current portion of deferred income tax

Under Canadian GAAP, deferred income tax relating to current assets or current liabilities must be classified as current. Under IFRS, deferred income tax balances are classified as long-term, irrespective of the classification of the assets or liabilities to which the deferred income tax relates or the expected timing of reversal. Accordingly, current deferred income tax assets reported under Canadian GAAP of $146 million at January 1, 2010 (December 31, 2010 – current deferred income tax assets of $59 million; March 31, 2010 – current deferred income tax liabilities of $5 million) have been reclassified as non-current under IFRS.

(l) Horizon major maintenance costs

Under Canadian GAAP, the Company would have deferred and amortized major maintenance turnaround costs on a straight-line basis over the period to the next scheduled major maintenance turnaround. Under IFRS, the Company has identified capitalized components of the original cost of an asset, which have a shorter useful life, and has amortized the costs of these components over the period to the next turnaround. At January 1, 2010, retained earnings decreased by $14 million, net of taxes of $5 million.

For the year ended December 31, 2010, net earnings decreased by $19 million, net of taxes of $6 million, and for the three months ended March 31, 2010, net earnings decreased by $5 million, net of taxes of $1 million, to reflect the impact of higher depletion charges.

(m) Long-term debt

Under Canadian GAAP, debt maturities within one year of the date of the balance sheet were classified as non-current on the basis that the Company had the intent and ability to refinance these obligations with its existing long-term credit facilities. Under IFRS, as the long-term debt maturing within one year was not payable to the same counterparty lenders as the long-term debt facility, $400 million was reclassified to current at January 1, 2010 (December 31, 2010 – $397 million; March 31, 2010 – $400 million).

Deferred income tax liabilities have been adjusted to give effect to adjustments as follows:

| | Note | Dec 31 2010 | Mar 31 2010 | Jan 1 2010 |
|---|---|---|---|---|
| **Deferred income tax assets as reported under Canadian GAAP** | | $ 59 | $ – | $ 146 |
| **Deferred income tax liabilities as reported under Canadian GAAP** | | (7,899) | (7,683) | (7,687) |
| Deferred income tax, net | | (7,840) | (7,683) | (7,541) |
| IFRS adjustments (increase) decrease | | | | |
| Deemed cost of property, plant and equipment | (a) | 25 | 12 | 9 |
| Share-based compensation | (c) | – | – | 49 |
| Asset retirement obligations | (e) | 134 | 130 | 128 |
| Risk management | (h) | 3 | 6 | 5 |
| PRT | (i) | (40) | (55) | (58) |
| UK deferred income tax liabilities | (j) | (80) | (95) | (61) |
| Horizon maintenance costs | (l) | 11 | 6 | 5 |
| Foreign exchange and other | | (1) | 17 | 2 |
| **Deferred income tax liabilities as reported under IFRS** | | $ (7,788) | $ (7,662) | $ (7,462) |

The following is a summary of transition adjustments, net of tax, to the Company's accumulated other comprehensive income from Canadian GAAP to IFRS:

| | Note | Dec 31 2010 | Mar 31 2010 | Jan 1 2010 |
|---|---|---|---|---|
| **Accumulated other comprehensive income as reported under Canadian GAAP** | | $ (167) | $ (152) | $ (104) |
| IFRS adjustments increase (decrease) | | | | |
| Cumulative translation adjustment on transition | (f) | 180 | 180 | 180 |
| Risk management | (h) | (15) | (6) | 1 |
| Translation of net investment | | 11 | 11 | – |
| **Accumulated other comprehensive income as reported under IFRS** | | $ 9 | $ 33 | $ 77 |

The following is a summary of transition adjustments, net of tax, to the Company's retained earnings from Canadian GAAP to IFRS:

| | Note | | Dec 31 2010 | | Mar 31 2010 | | Jan 1 2010 |
|---|---|---|---|---|---|---|---|
| **Retained earnings as reported under Canadian GAAP** | | $ | 18,005 | $ | 17,481 | $ | 16,696 |
| IFRS adjustments (increase) decrease | | | | | | | |
| Deemed cost of property, plant and equipment | (a) | | (94) | | (69) | | (53) |
| Share-based compensation | (c) | | (128) | | (250) | | (170) |
| Asset retirement obligations | (e) | | (227) | | (215) | | (212) |
| Cumulative translation adjustment | (f) | | (180) | | (180) | | (180) |
| Risk management | (h) | | (3) | | (9) | | (13) |
| PRT | (i) | | (40) | | (55) | | (58) |
| UK deferred income tax liabilities | (j) | | (80) | | (95) | | (61) |
| Horizon maintenance costs | (l) | | (33) | | (19) | | (14) |
| Other | | | (8) | | (8) | | (8) |
| Retained earnings as reported under IFRS | | $ | 17,212 | $ | 16,581 | $ | 15,927 |

**Adjustments to the statements of cash flows**

The transition from Canadian GAAP to IFRS had no significant impact on cash flows generated by the Company.

## SUPPLEMENTARY INFORMATION

## INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated October 2009. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended March 31, 2011:

| | |
|---|---|
| Interest coverage (times) | |
| Net earnings [(1)] | 4.9x |
| Cash flow from operations [(2)] | 15.1x |

*(1) Net earnings plus income taxes and interest expense excluding current and deferred PRT expense; divided by the sum of interest expense and capitalized interest.*

*(2) Cash flow from operations plus current income taxes and interest expense excluding current PRT expense; divided by the sum of interest expense and capitalized interest.*

## CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Friday, May 6, 2011. The North American conference call number is 1-800-952-6845 and the outside North American conference call number is 001-416-695-7848. Please call in about 10 minutes before the starting time in order to be patched into the call. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Friday, May 13, 2011. To access the postview in North America, dial 1-800-408-3053. Those outside of North America, dial 001-905-694-9451. The passcode to use is 8624654.

## WEBCAST

This call is being webcast and can be accessed on Canadian Natural's website at www.cnrl.com.

For further information, please contact:


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