Press Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2012 FIRST QUARTER RESULTS

CALGARY, ALBERTA – MAY 3, 2012 – FOR IMMEDIATE RELEASE

Commenting on first quarter results, Canadian Natural's Vice-Chairman John Langille stated, "Our balanced asset base and production mix are key components to our strategy of creating long term shareholder value throughout the commodity price cycles. We exited Q1/12 in a strong financial position and continue to have a high degree of flexibility in our capital allocation. This drives our ability to transition to more sustainable, longer life production delivered from our existing asset base. The strength of our portfolio is evident as we target to grow production from Q4/11 to Q4/12 by 10% while spending within cash flow and allocating more than half our 2012 capital budget to projects for future production."

Steve Laut, President of Canadian Natural continued, "Production was successfully re-started at Horizon on March 13, 2012. The third ore preparation plant and associated hydro-transport unit were fully integrated into operations in the quarter and contributed to solid production of approximately 111,500 bbl/d in April. Our thermal in situ operations are heading into a production cycle following completion of the steaming cycle and we are targeting a strong ramp up in production through to the end of the year. In addition, our primary heavy crude oil achieved record quarterly production and Canadian light crude oil and NGLs will continue to be strong drivers of value growth in 2012."

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended Mar 31 2012	Dec 31 2011	Mar 31 2011
Net earnings	**$ 427**	$ 832	$ 46
Per common share - basic	**$ 0.39**	$ 0.76	$ 0.04
- diluted	**$ 0.39**	$ 0.76	$ 0.04
Adjusted net earnings from operations (1)	**$ 300**	$ 972	$ 228
Per common share - basic	**$ 0.27**	$ 0.89	$ 0.21
- diluted	**$ 0.27**	$ 0.88	$ 0.21
Cash flow from operations (2)	**$ 1,280**	$ 2,158	$ 1,074
Per common share - basic	**$ 1.16**	$ 1.97	$ 0.98
- diluted	**$ 1.16**	$ 1.96	$ 0.97
Capital expenditures, net of dispositions	**$ 1,596**	$ 1,909	$ 1,694
Daily production, before royalties			
Natural gas (MMcf/d)	**1,302**	1,280	1,256
Crude oil and NGLs (bbl/d)	**395,461**	444,286	356,988
Equivalent production (BOE/d) (3)	**612,279**	657,599	566,231

(1) 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 the Management's Discussion and Analysis ("MD&A").

(2) 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.

(3) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if 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 a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

- Total crude oil and NGLs production averaged 395,461 bbl/d in Q1/12 representing an increase of 11% over Q1/11 and a decrease of 11% from Q4/11. The increase in production over Q1/11 reflects the successful results of primary heavy crude oil and light crude oil drilling programs and increased production from Horizon partially offset by the timing of steaming cycles in Bitumen ("thermal in situ"). The decrease in production from Q4/11 was a result of the temporary suspension of production at Horizon. On February 5, 2012 production at Horizon was suspended for unplanned maintenance on the fractionating unit. Production for the quarter exceeded previously issued guidance as a result of resuming production on March 13, 2012, earlier than originally anticipated.

- Total natural gas production for Q1/12 was 1,302 MMcf/d representing an increase of 4% over Q1/11 and 2% over Q4/11. The increase in production reflects the impact of natural gas producing properties acquired during 2011 and strong results from the Company's modest, liquids rich drilling program offset by natural declines.

- Canadian Natural generated quarterly cash flow from operations of $1.28 billion compared to $1.07 billion in Q1/11 and $2.16 billion in Q4/11. The increase in cash flow from Q1/11 was primarily related to higher sales volumes from the Company's North America crude oil and NGLs and oil sands mining operations. The decrease in cash flow from Q4/11 was primarily related to lower synthetic crude oil ("SCO") sales volumes, lower crude oil and NGLs netbacks and lower natural gas prices.

- AECO benchmark natural gas prices were down 27% in Q1/12 from Q4/11. This reduction in pricing was responsible for approximately $75 million less after-tax cash flow in Q1/12. The lower current strip AECO natural gas prices for full year 2012 when compared to original budget targets an after-tax cash flow reduction of approximately $550 million. As a result, the Company has reduced natural gas capital expenditures by $190 million from original budget and has reduced full year targeted drilling to 36 net wells.

- Adjusted net earnings from operations for the quarter was $300 million, compared to adjusted net earnings of $228 million in Q1/11 and $972 million in Q4/11. Changes in adjusted net earnings reflect the changes in cash flow from operations.

- North America light crude oil and NGLs quarterly production increased 19% compared to Q1/11 and increased 7% compared to Q4/11 as a result of a successful light oil drilling program and increased liquid recoveries from Septimus following the completion of a tie in to a deep cut facility.

- Primary heavy crude oil production increased 24% compared to Q1/11 and 8% compared to Q4/11, achieving record quarterly production exceeding 120,000 bbl/d. Canadian Natural targets to drill approximately 815 net primary heavy crude oil wells in 2012 and increase production by 19% over 2011, 3% above original expectations primarily due to better than expected results from Woodenhouse. Woodenhouse is a new non-traditional primary heavy crude oil area located 75 kilometers north of Pelican Lake.

- At Horizon, the third ore preparation plant ("OPP") and associated hydro-transport unit were successfully integrated into operations in the quarter. The third OPP is expected to increase production reliability going forward by allowing the Company to maintain steady feedstock to the upgrader with two of the three OPPs continually on stream. SCO production in April 2012 averaged approximately 111,500 bbl/d.

- The WCS heavy crude oil differential as a percent of WTI averaged 21% in Q1/12. The WCS heavy differential widened in Q1/12 from Q4/11 as a result of planned and unplanned maintenance at key refineries in the United States and Canada. The WCS heavy crude oil differential as a percent of WTI widened to 29% in March and 32% in April. As expected, the differential for May narrowed to 19% and indications in June are for further tightening to approximately 14% as refineries come back on stream.

- Subsequent to Q1/12, Toronto Stock Exchange accepted notice of Canadian Natural's renewal of its Normal Course Issuer Bid through the facilities of Toronto Stock Exchange and the New York Stock Exchange. The notice provides that Canadian Natural may, during the 12 month period commencing April 9, 2012 and ending April 8, 2013, purchase for cancellation on Toronto Stock Exchange and the New York Stock Exchange up to 55,027,447 shares.

- Canadian Natural purchased 692,200 common shares in the quarter for cancellation at a weighted average price of $33.11 per common share. Subsequent to the quarter, the Company purchased a further 521,100 common shares at a weighted average price of $32.21 per common share.

- Declared a quarterly cash dividend on common shares of $0.105 per common share payable July 1, 2012.

GOVERNANCE UPDATE

As part of the Company's commitment to good governance practices, the Board of Directors has appointed Ambassador Gordon D. Giffin as independent lead Director concurrently with the Company's Annual and Special Meeting of Shareholders on May 3, 2012.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in core regions where it can own a substantial land base and associated infrastructure. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated 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; light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, Bitumen ("thermal in situ"), SCO (herein collectively referred to as "crude oil"), natural gas 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			
	2012		2011	
	Gross	**Net**	Gross	Net
Crude oil	**300**	**278**	290	279
Natural gas	**21**	**19**	28	25
Dry	**6**	**6**	17	16
Subtotal	**327**	**303**	335	320
Stratigraphic test / service wells	**584**	**584**	502	501
Total	**911**	**887**	837	821
Success rate (excluding stratigraphic test / service wells)		**98%**		95%

North America Exploration and Production

North America crude oil and NGLs

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Crude oil and NGLs production (bbl/d)	**305,613**	291,839	290,130
Net wells targeting crude oil	**284**	345	293
Net successful wells drilled	**278**	330	279
Success rate	**98%**	96%	95%

- North America crude oil and NGLs production were within previously issued guidance for the quarter as a result of efficient and effective operations. Production averaged 305,613 bbl/d in Q1/12 representing an increase of 5% from Q1/11 and Q4/11. The increase in production was a result of successful primary heavy and light crude oil drilling programs.

- Primary heavy crude oil production increased 24% compared to Q1/11 and 8% compared to Q4/11, achieving record quarterly production exceeding 120,000 bbl/d. Canadian Natural targets to drill approximately 815 net primary heavy crude oil wells in 2012 and increase production by 19% over 2011, 3% above original expectations primarily due to better than expected results from Woodenhouse. Woodenhouse is a new non-traditional primary heavy crude oil area located 75 kilometers north of Pelican Lake.

- North America light crude oil and NGLs quarterly production increased 19% compared to Q1/11 and increased 7% compared to Q4/11 as a result of a successful light oil drilling program and increased liquid recoveries from Septimus following the completion of a tie in to a deep cut facility. North America light crude oil and NGLs is a significant part of Canadian Natural's balanced portfolio, averaging approximately 66,000 bbl/d in the quarter.

- At Pelican Lake, reservoir performance continues to be positive. The Company is constructing a 25,000 bbl/d battery and targets to drill eight injectors and 78 producers in 2012. The Company targets to ultimately recover 561 million barrels (363 million barrels of proved plus probable reserves and 198 million barrels of contingent resources) of additional crude oil from this world class crude oil pool.

- As expected, thermal in situ production averaged approximately 80,000 bbl/d in Q1/12 as a result of the timing of steaming cycles. Production is targeted to ramp up in the second quarter as pads re-enter the production cycle. The Company targets to increase production by 8% in 2012 over 2011.

- Canadian Natural has a robust portfolio of steam assisted gravity drainage ("SAGD") projects with the potential to grow thermal in situ production to approximately 480,000 bbl/d of capacity. Each project will be used as a template for the projects that follow, allowing the Company to continually refine development and optimize performance. The Company targets to add 40,000 to 60,000 bbl/d of production every two to three years through the development of these projects.

    - Kirby South Phase 1 remains on cost and on schedule with first steam-in targeted for late 2013. Drilling is progressing on the fourth of seven pads with wells confirming geological expectations. The total project was 42% complete at the end of the quarter.

    - Construction preparation work is underway on Kirby North Phase 1 including construction of the main access road and clearing of the plant site. First steam-in is targeted for 2016.

    - The regulatory approval application for Grouse was submitted in the quarter with first steam-in targeted for 2017.

    - Canadian Natural has an active stratigraphic ("strat") test well drilling program to delineate the reservoir characteristics for future projects. The Company drilled 355 strat test and observation wells in the quarter.

- In Q2/12, the Company plans to drill 44 net thermal in situ wells and 182 net crude oil wells, excluding strat test and service wells.

- North America crude oil and NGLs operating costs increased to $15.40/bbl from $12.28/bbl in Q1/11 and $14.32/bbl in Q4/11. The increase was primarily due to higher primary heavy crude oil operating costs as a result of increased trucking costs, facility treating constraints (Lindbergh expansion targeted for Q3/12), drilling more wells than budgeted in Q1/12, seasonality and the impact of greater than forecasted production from Woodenhouse. Notwithstanding these Q1/12 costs, 2012 full year operating cost guidance for North America crude oil and NGLs remains at $11.00/bbl to $13.00/bbl.

North America natural gas

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Natural gas production (MMcf/d)	**1,281**	1,255	1,225
Net wells targeting natural gas	**19**	29	26
Net successful wells drilled	**19**	27	25
Success rate	**100%**	93%	96%

- North America natural gas production for the quarter averaged 1,281 MMcf/d representing an increase of 5% from Q1/11 and an increase of 2% from Q4/11. The increase in production was a result of natural gas producing properties acquired in 2011 and strong results from the Company's modest, liquids rich drilling program offset by natural declines.

- AECO benchmark natural gas prices were down 27% in Q1/12 from Q4/11. This reduction in pricing was responsible for approximately $75 million less after-tax cash flow in Q1/12. The lower current strip AECO natural gas prices for full year 2012 when compared to original budget targets an after-tax cash flow reduction of approximately $550 million. As a result, the Company has reduced natural gas capital expenditures by $190 million from original budget and has reduced full year targeted drilling to 36 net wells.
- In Q1/12 the Company has shut-in approximately 16 MMcf/d of natural gas in addition to the approximately 20 MMcf/d shut-in in Q4/11. The Company has a strategic plan to shut-in certain additional natural gas volumes of approximately 22 MMcf/d if natural gas prices remain below economic thresholds in those areas.
- At Septimus, the plant expansion remains on track and on budget. The expansion will increase sales capacity to 110 MMcf/d and approximately 11,000 bbl/d of liquids. The Company targets to drill 10 net natural gas wells in 2012, reflecting a reduction of 7 net natural gas wells from the previous forecast.
- North America natural gas operating costs increased to $1.33/Mcf from $1.16/Mcf in Q1/11 and $1.12/Mcf in Q4/11. The increase was a result of seasonal winter costs and high operating cost properties acquired in the fourth quarter of 2011. Canadian Natural expects operating costs to decline once acquired properties have been fully integrated with existing operations. 2012 full year operating cost guidance for North America natural gas remains at $1.10/Mcf to $1.20/Mcf.

International Exploration and Production

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Crude oil production (bbl/d)			
North Sea	**23,046**	26,769	34,101
Offshore Africa	**20,712**	22,726	25,488
Natural gas production (MMcf/d)			
North Sea	**3**	6	9
Offshore Africa	**18**	19	22
Net wells targeting crude oil	**0.0**	0.0	0.9
Net successful wells drilled	**0.0**	0.0	0.0
Success rate	**0%**	0%	0%

- North Sea crude oil production averaged 23,046 bbl/d during Q1/12 representing a decrease of 32% compared to Q1/11 and a decrease of 14% compared to Q4/11. The decrease from Q1/11 was a result of suspended operations at Banff/Kyle due to damage suffered to the floating production storage offloading vessel (“FPSO”) from severe storm conditions.
- In Q4/11, the Banff/Kyle FPSO was removed from the field after suffering damage from severe storm conditions. The Company is assessing the extent of the damage including associated costs. The incident is an insurable event for both property damage and business interruption insurance.
- Production in Offshore Africa averaged 20,712 bbl/d during Q1/12 representing a decrease of 19% compared to Q1/11 and a decrease of 9% compared to Q4/11. The decrease from Q1/11 was a result of natural field declines. Infill drilling at the Espoir Field is targeted to begin in late 2012, targeting additional production of 6,500 BOE/d at the completion of this drilling program.
- Subsequent to the quarter, Canadian Natural acquired a 36% interest in Block 514 in Côte d’Ivoire. This block’s areal extent is approximately 1,250 square km and has an initial 3 year term in which 3D seismic data will be acquired and a well will be drilled. The Company believes this block is prospective for deepwater channel/fan plays similar to recent discoveries in Ghana and elsewhere in offshore Africa.
- North Sea and Offshore Africa realized crude oil prices increased in Q1/12 by 7% and 26% respectively from Q4/11 partially as a result of the increase in the Brent benchmark pricing.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Synthetic crude oil production ("SCO") (bbl/d)	**46,090**	102,952	7,269

- SCO production at Horizon averaged 46,090 bbl/d in Q1/12. The decrease from Q4/11 was due to the temporary suspension of production. On February 5, 2012 production at Horizon was suspended for unplanned maintenance on the fractionating unit. Production for the quarter exceeded previously issued guidance as a result of resuming production on March 13, 2012, earlier than originally anticipated. Production in April 2012 averaged approximately 111,500 bbl/d.
- The third OPP and associated hydro-transport unit were successfully integrated into operations in the quarter. The third OPP is expected to increase production reliability going forward by allowing the Company to maintain steady feedstock to the upgrader with two of the three OPPs continually on stream.
- Canadian Natural's staged expansion to 250,000 bbl/d of SCO production capacity continues to progress on track. Thus far, the Company's strategy to break the expansion down into smaller more focused projects has proven to be effective. The project capital budget for Horizon for 2012 is $1.88 billion and projects currently under construction are trending at or below cost estimates.

MARKETING

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Crude oil and NGLs pricing			
WTI benchmark price (US$/bbl) (1)	**$ 102.94**	$ 94.02	$ 94.25
Western Canadian Select blend differential from WTI (%)	**21%**	11%	24%
SCO price (US$/bbl) (2)	**$ 98.11**	$ 102.95	$ 95.24
Average realized pricing before risk management (C$/bbl) (3)	**$ 80.08**	$ 85.28	$ 67.96
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 2.39**	$ 3.29	$ 3.57
Average realized pricing before risk management (C$/Mcf)	**$ 2.47**	$ 3.50	$ 3.83

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

(2) Synthetic crude oil ("SCO").

(3) Excludes SCO.

- In Q1/12, WTI pricing increased by 9% from Q1/11 and Q4/11 partially due to supply and demand imbalances.
- The WCS heavy crude oil differential as a percent of WTI averaged 21% in Q1/12. The WCS heavy differential widened in Q1/12 from Q4/11 as a result of planned and unplanned maintenance at key refineries in the United States and Canada. The WCS heavy crude oil differential as a percent of WTI widened to 29% in March and 32% in April. As expected, the differential for May narrowed to 19% and indications in June are for further tightening to approximately 14% as refineries come back on stream.
- During Q1/12, Canadian Natural contributed 152,000 bbl/d of its heavy crude oil stream to the WCS blend. The Company is the largest contributor of the WCS blend, accounting for 51%.
- AECO benchmark natural gas prices decreased 33% compared to Q1/11 and 27% compared to Q4/11, due to supply and demand imbalances in North America.

REDWATER UPGRADING AND REFINING

Supporting and participating in projects that add incremental conversion capacity is a key part of the Company's marketing strategy. Canadian Natural, in a partnership agreement with North West Upgrading Inc., continues to move forward with detailed engineering regarding the construction and operation of a bitumen refinery near Redwater, Alberta. Project development is dependent upon completion of detailed engineering and final project sanction by the partnership and its partners and approval of the final tolls. Board sanction is currently targeted in 2012.

FINANCIAL REVIEW

The financial position of Canadian Natural remains strong as the Company continues to implement proven strategies and focus on disciplined capital allocation. Canadian Natural's cash flow generation, credit facilities, its diverse asset base and related capital expenditure programs, and commodity hedging policy all support a flexible financial position and provide the right financial resources for the short, mid and long term. Supporting this are:

- A large and diverse asset base spread over various commodity types; average production amounted to 612,279 BOE/d in Q1/12 with over 96% of production located in G8 countries.
- A strong balance sheet with debt to book capitalization of 26% and debt to EBITDA of 1.0. At March 31, 2012 long-term debt amounted to $8.2 billion compared with $8.5 billion at March 31, 2011.
- Canadian Natural maintains significant financial stability and liquidity represented by approximately $4.1 billion in available unused bank lines at the end of the quarter.
- Canadian Natural's commodity hedging program protects investment returns, ensures ongoing balance sheet strength and supports the Company's cash flow for its capital expenditures programs. The Company has hedged approximately 50% of the remaining three quarters of forecasted 2012 crude oil volumes through a combination of puts and collars.
- Subsequent to Q1/12, Toronto Stock Exchange accepted notice of Canadian Natural's renewal of its Normal Course Issuer Bid through the facilities of Toronto Stock Exchange and the New York Stock Exchange. The notice provides that Canadian Natural may, during the 12 month period commencing April 9, 2012 and ending April 8, 2013, purchase for cancellation on Toronto Stock Exchange and the New York Stock Exchange up to 55,027,447 shares.
- Canadian Natural purchased 692,200 common shares in the quarter for cancellation at a weighted average price of $33.11 per common share. Subsequent to the quarter, the Company purchased a further 521,100 common shares at a weighted average price of $32.21 per common share.
- Declared a quarterly cash dividend on common shares of $0.105 per common share payable July 1, 2012.

OUTLOOK

The Company forecasts 2012 production levels before royalties to average between 1,220 and 1,260 MMcf/d of natural gas and between 440,000 and 480,000 bbl/d of crude oil and NGLs. Q2/12 production guidance before royalties is forecast to average between 1,250 and 1,270 MMcf/d of natural gas and between 453,000 and 482,000 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.

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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 operations and future expansion, Primrose, Pelican Lake, the Kirby Thermal Oil Sands Project, the Keystone XL Pipeline US Gulf Coast expansion, and the construction and future operations of the North West Redwater bitumen upgrader and 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 and proved plus probable 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 disruptions or delays in the resumption of the mining, extracting or upgrading of 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, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

Management's Discussion and Analysis

This MD&A 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, 2012 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2011.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's consolidated financial statements for the period ended March 31, 2012 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, 2010 comparative figures have been restated in accordance with IFRS issued as at December 31, 2011. 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.

A Barrel of Oil Equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if 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 a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light & medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil.

Production volumes and per unit 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, 2012 in relation to the first quarter of 2011 and the fourth quarter of 2011. The accompanying tables form an integral part of this MD&A. This MD&A is dated May 3, 2012. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2011, 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 2012	Dec 31 2011	Mar 31 2011
Product sales	**$ 3,971**	$ 4,788	$ 3,302
Net earnings	**$ 427**	$ 832	$ 46
Per common share – basic	**$ 0.39**	$ 0.76	$ 0.04
– diluted	**$ 0.39**	$ 0.76	$ 0.04
Adjusted net earnings from operations (1)	**$ 300**	$ 972	$ 228
Per common share – basic	**$ 0.27**	$ 0.89	$ 0.21
– diluted	**$ 0.27**	$ 0.88	$ 0.21
Cash flow from operations (2)	**$ 1,280**	$ 2,158	$ 1,074
Per common share – basic	**$ 1.16**	$ 1.97	$ 0.98
– diluted	**$ 1.16**	$ 1.96	$ 0.97
Capital expenditures, net of dispositions	**$ 1,596**	$ 1,909	$ 1,694

(1) 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.

(2) 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 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

($ millions)	*Three Months Ended*		
	Mar 31 2012	*Dec 31 2011*	*Mar 31 2011*
Net earnings as reported	***$ 427***	*$ 832*	*$ 46*
Share-based compensation (recovery) expense, net of tax (1)	***(107)***	*207*	*128*
Unrealized risk management loss, net of tax (2)	***40***	*50*	*39*
Unrealized foreign exchange gain, net of tax (3)	***(60)***	*(117)*	*(89)*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (4)	***–***	*–*	*104*
Adjusted net earnings from operations	***$ 300***	*$ 972*	*$ 228*

(1) 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.

(2) 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.

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

(4) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's 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. During the first quarter of 2011, the UK government 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.

Cash Flow from Operations

($ millions)	Three Months Ended **Mar 31 2012**	Dec 31 2011	Mar 31 2011
Net earnings	***$ 427***	*$ 832*	*$ 46*
Non-cash items:			
Depletion, depreciation and amortization	***975***	*998*	*849*
Share-based compensation (recovery) expense	***(107)***	*207*	*128*
Asset retirement obligation accretion	***37***	*33*	*33*
Unrealized risk management loss	***60***	*58*	*54*
Unrealized foreign exchange gain	***(60)***	*(117)*	*(89)*
Deferred income tax (recovery) expense	***(52)***	*144*	*53*
Horizon asset impairment provision	***–***	*–*	*396*
Insurance recovery – property damage	***–***	*3*	*(396)*
Cash flow from operations	***$ 1,280***	*$ 2,158*	*$ 1,074*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the first quarter of 2012 were $427 million compared to $46 million for the first quarter of 2011 and $832 million for the fourth quarter of 2011. Net earnings for the first quarter of 2012 included net after-tax income of $127 million, compared to net after-tax expenses of $182 million for the first quarter of 2011, and net after-tax expenses of $140 million for the fourth quarter of 2011 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. Excluding these items, adjusted net earnings from operations for the first quarter of 2012 were $300 million, compared to $228 million for the first quarter of 2011 and $972 million for the fourth quarter of 2011.

The increase in adjusted net earnings for the first quarter of 2012 from the first quarter of 2011 was primarily due to:

- higher sales volumes in North America and Horizon segments;
- the impact of a weaker Canadian dollar; and
- higher crude oil and NGLs netbacks;

partially offset by:

- lower natural gas netbacks;
- higher depletion, depreciation and amortization expense; and
- higher realized risk management losses.

The decrease in adjusted net earnings for the first quarter of 2012 from the fourth quarter of 2011 was primarily due to:

- lower synthetic crude oil sales volumes, primarily due to unplanned maintenance on the fractionating unit in the Horizon primary upgrading facility;
- lower crude oil and NGLs and natural gas netbacks;
- higher administration expense;
- higher interest and other financing costs;
- higher realized risk management losses; and
- the impact of a stronger Canadian dollar;

partially offset by:

- higher North America crude oil and NGLs sales volumes; and
- lower depletion, depreciation and amortization expense.

The impacts of share-based compensation, 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 2012 was $1,280 million compared to $1,074 million for the first quarter of 2011 and $2,158 million for the fourth quarter of 2011. The increase in cash flow from operations from the first quarter of 2011 was primarily due to the factors noted above relating to the increase in adjusted net earnings, excluding depletion, depreciation and amortization expense, partially offset by higher cash taxes.

The decrease in cash flow from operations from the fourth quarter of 2011 was primarily due to the factors noted above relating to the decrease in adjusted net earnings, excluding depletion, depreciation and amortization expense, partially offset by lower cash taxes.

Total production before royalties for the first quarter of 2012 increased by 8% to 612,279 BOE/d from 566,231 BOE/d for the first quarter of 2011 and decreased by 7% from 657,599 BOE/d for the fourth quarter of 2011. Production for the first quarter of 2012 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 2012**		Dec 31 2011		Sep 30 2011		Jun 30 2011
Product sales	**$**	**3,971**	$	4,788	$	3,690	$	3,727
Net earnings	**$**	**427**	$	832	$	836	$	929
Net earnings per common share								
– basic	**$**	**0.39**	$	0.76	$	0.76	$	0.85
– diluted	**$**	**0.39**	$	0.76	$	0.76	$	0.84

($ 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)	$	0.54	$	0.60
– diluted	$	0.04	$	(0.28)	$	0.54	$	0.60

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, the impact of the WCS Heavy Differential ("WCS Differential") from WTI in North America and the impact of the differential between WTI and Dated Brent benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of 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 and recommencement of production at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa, and payout of the Baobab field in May 2011.
- **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 and timing 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, acquisitions of natural gas producing properties that have higher operating costs per Mcf than the Company's existing properties, and the suspension and recommencement of production at Horizon.

- **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 suspension and recommencement of production at Horizon and the impact of impairments at the Olowi field in Offshore Gabon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model 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 that 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 realized and 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 include statutory tax rate and other legislative changes substantively enacted in the various periods.

BUSINESS ENVIRONMENT

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
WTI benchmark price (US$/bbl) [1]	**$ 102.94**	$ 94.02	$ 94.25
Dated Brent benchmark price (US$/bbl)	**$ 118.47**	$ 109.29	$ 105.01
WCS blend differential from WTI (US$/bbl)	**$ 21.47**	$ 10.49	$ 22.74
WCS blend differential from WTI (%)	**21%**	11%	24%
SCO price (US$/bbl) [2]	**$ 98.11**	$ 102.95	$ 95.24
Condensate benchmark price (US$/bbl)	**$ 110.05**	$ 108.68	$ 98.57
NYMEX benchmark price (US$/MMBtu)	**$ 2.77**	$ 3.61	$ 4.13
AECO benchmark price (C$/GJ)	**$ 2.39**	$ 3.29	$ 3.57
US/Canadian dollar average exchange rate (US$)	**$ 0.9989**	$ 0.9773	$ 1.0147

(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$102.94 per bbl for the first quarter of 2012, an increase of 9% from US$94.25 per bbl for the first quarter of 2011, and an increase of 9% from US$94.02 per bbl for the fourth quarter of 2011. WTI pricing was reflective of the political instability in the Middle East, the optimism in the United States economy, and the expected commencement of the Seaway pipeline reversal from Cushing to the Gulf Coast, offset by lower than expected growth in Asian demand.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Dated Brent ("Brent") pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$118.47 per bbl for first quarter of 2012, an increase of 13% compared to US$105.01 per bbl for the first quarter of 2011 and an increase of 8% from US$109.29 per bbl for the fourth quarter of 2011. The higher Brent pricing relative to WTI was primarily due to the limited pipeline capacity between Petroleum Administration for Defence Districts II ("PADD II") and the United States Gulf Coast. This logistical constraint is preventing WTI priced barrels delivered into PADD II from obtaining United States Gulf Coast Brent-based pricing.

The WCS Heavy Differential averaged 21% for the first quarter of 2012, compared to 24% in the first quarter of 2011, and 11% for the fourth quarter of 2011. The WCS Heavy Differential widened in the first quarter of 2012, compared to the fourth quarter of 2011, as a result of planned and unplanned maintenance at key PADD II refineries.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. The condensate premium dropped to a more typical 7% premium in the first quarter of 2012 from 16% in the fourth quarter of 2011 as condensate supply and demand were more balanced.

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 Heavy Differential is expected to continue to reflect seasonal demand fluctuations, changes in transportation logistics and refinery margins.

NYMEX natural gas prices averaged US$2.77 per MMBtu for the first quarter of 2012, a decrease of 33% from US$4.13 per MMBtu for the first quarter of 2011, and a decrease of 23% from US$3.61 per MMBtu for the fourth quarter of 2011. AECO natural gas prices for the first quarter of 2012 averaged $2.39 per GJ, a decrease of 33% from $3.57 per GJ for the first quarter of 2011, and a decrease of 27% from $3.29 per GJ for the fourth quarter of 2011.

Overall natural gas prices continue to be weak in response to the strong North America supply position, primarily from the highly productive shale areas. Additionally, weather related natural gas demand was lower in the first quarter of 2012 as a result of warmer than normal winter temperatures.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**305,613**	291,839	290,130
North America – Oil Sands Mining and Upgrading	**46,090**	102,952	7,269
North Sea	**23,046**	26,769	34,101
Offshore Africa	**20,712**	22,726	25,488
	395,461	444,286	356,988
Natural gas (MMcf/d)			
North America	**1,281**	1,255	1,225
North Sea	**3**	6	9
Offshore Africa	**18**	19	22
	1,302	1,280	1,256
Total barrels of oil equivalent (BOE/d)	**612,279**	657,599	566,231
Product mix			
Light and medium crude oil and NGLs	**18%**	17%	21%
Pelican Lake heavy crude oil	**6%**	6%	7%
Primary heavy crude oil	**20%**	17%	17%
Bitumen (thermal oil)	**13%**	12%	17%
Synthetic crude oil	**8%**	16%	1%
Natural gas	**35%**	32%	37%
Percentage of product sales (1) (excluding midstream revenue)			
Crude oil and NGLs	**91%**	90%	84%
Natural gas	**9%**	10%	16%

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

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**253,951**	230,522	233,554
North America – Oil Sands Mining and Upgrading	**43,599**	98,287	6,978
North Sea	**22,986**	26,714	34,008
Offshore Africa	**17,497**	19,331	23,213
	338,033	374,854	297,753
Natural gas (MMcf/d)			
North America	**1,277**	1,211	1,197
North Sea	**3**	6	9
Offshore Africa	**15**	16	19
	1,295	1,233	1,225
Total barrels of oil equivalent (BOE/d)	**553,752**	580,242	501,914

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.

Crude oil and NGLs production for the first quarter of 2012 increased 11% to 395,461 bbl/d from 356,988 bbl/d for the first quarter of 2011 and decreased 11% from 444,286 bbl/d for the fourth quarter of 2011. The increase in production for the first quarter of 2012 from the first quarter of 2011 was primarily related to increased production at Horizon, the impact of a strong heavy crude oil drilling program, and the cyclic nature of the Company's thermal operations. The decrease from the fourth quarter of 2011 was primarily related to the temporary suspension of production at Horizon during the first quarter of 2012. Crude oil and NGLs production in the first quarter of 2012 was within the Company's previously issued guidance of 367,000 to 400,000 bbl/d.

Natural gas production for the first quarter of 2012 increased by 4% to 1,302 MMcf/d from 1,256 MMcf/d from the first quarter of 2011 and increased by 2% from 1,280 MMcf/d from the fourth quarter of 2011. The increase in natural gas production from the comparable periods in 2011 reflects the new production volumes from natural gas producing properties acquired during 2011. 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. The Company shut in approximately 16 MMcf/d of natural gas production in the first quarter of 2012 due to low natural gas prices. Natural gas production in the first quarter of 2012 was within the Company's previously issued guidance of 1,300 to 1,320 MMcf/d.

For 2012, annual production guidance is targeted to average between 440,000 and 480,000 bbl/d of crude oil and NGLs and between 1,220 and 1,260 MMcf/d of natural gas. Second quarter 2012 production guidance is targeted to average between 453,000 and 482,000 bbl/d of crude oil and NGLs and between 1,250 and 1,270 MMcf/d of natural gas.

North America – Exploration and Production

For the first quarter of 2012, crude oil and NGLs production increased 5% to average 305,613 bbl/d, compared to 290,130 bbl/d for the first quarter of 2011 and 291,839 bbl/d for the fourth quarter of 2011. Increases in crude oil and NGLs production from comparable periods were primarily due to the impact of a strong heavy crude 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 297,000 bbl/d to 309,000 bbl/d for the first quarter of 2012. Second quarter 2012 production guidance is targeted to average between 312,000 and 325,000 bbl/d of crude oil and NGLs.

Natural gas production increased 5% to 1,281 MMcf/d for the first quarter of 2012 compared to 1,225 MMcf/d in the first quarter of 2011 and increased 2% compared to 1,255 MMcf/d in the fourth quarter of 2011. Natural gas production for the first quarter of 2012 and the fourth quarter of 2011 reflected new production volumes from natural gas producing properties acquired during 2011, offset by the impact of 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. During the first quarter of 2012, the Company reduced its drilling activities and shut in approximately 16 MMcf/d of gas volumes due to natural gas price declines.

North America – Oil Sands Mining and Upgrading

For the first quarter of 2012, crude oil and NGLs production averaged 46,090 bbl/d, compared to 7,269 bbl/d for the first quarter of 2011 and 102,952 bbl/d for the fourth quarter of 2011.

The Company temporarily suspended synthetic crude oil production at Horizon on February 5, 2012 to complete unplanned maintenance on the fractionating unit in the primary upgrading facility. On March 13, 2012 the Company successfully and safely completed the unplanned maintenance on the fractionating unit. Second quarter 2012 production guidance is targeted to average between 105,000 and 115,000 bbl/d of SCO.

North Sea

First quarter 2012 North Sea crude oil production decreased 32% to 23,046 bbl/d from 34,101 bbl/d for the first quarter of 2011, and decreased 14% from 26,769 bbl/d for the fourth quarter of 2011. The decrease in production volumes from the comparable periods in 2011 was primarily due to natural field declines and the suspension of production at Banff/Kyle. In December 2011, the Banff Floating Production, Storage and Offloading Vessel (“FPSO”) and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended and appropriate shut down procedures were activated. The FPSO and associated floating storage unit have subsequently been removed from the field, and the extent of the damage, including associated costs and timing of returning to the field, is currently being assessed.

Offshore Africa

First quarter crude oil production averaged 20,712 bbl/d, decreasing 19% from 25,488 bbl/d for the first quarter of 2011 and 9% from 22,726 in the fourth quarter of 2011. The decrease in production volumes from the comparable periods in 2011 was due to natural field declines and the payout of the Baobab field in May 2011.

International Guidance

The Company’s North Sea and Offshore Africa first quarter 2012 crude oil and NGLs production was within the Company’s previously issued guidance of 40,000 to 46,000 bbl/d. Second quarter 2012 production guidance is targeted to average between 36,000 and 42,000 bbl/d of crude oil.

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 2012**	Dec 31 2011	Mar 31 2011
North America – Exploration and Production	**621,277**	557,475	–
North America – Oil Sands Mining and Upgrading (SCO)	**1,053,025**	1,021,236	802,575
North Sea	**84,112**	286,633	587,121
Offshore Africa	**853,074**	527,312	645,897
	2,611,488	2,392,656	2,035,593

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 80.08**	$ 85.28	$ 67.96
Royalties	**13.08**	15.53	10.43
Production expense	**16.78**	16.85	14.30
Netback	**$ 50.22**	$ 52.90	$ 43.23
Natural gas ($/Mcf) (1)			
Sales price (2)	**$ 2.47**	$ 3.50	$ 3.83
Royalties	**0.05**	0.18	0.13
Production expense	**1.34**	1.15	1.17
Netback	**$ 1.08**	$ 2.17	$ 2.53
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	**$ 55.21**	$ 61.21	$ 51.33
Royalties	**8.23**	10.14	6.87
Production expense	**13.43**	13.12	11.59
Netback	**$ 33.55**	$ 37.95	$ 32.87

(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 2012	Dec 31 2011	Mar 31 2011
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 74.27**	$ 81.02	$ 62.21
North Sea	**$ 117.03**	$ 109.71	$ 102.51
Offshore Africa	**$ 128.94**	$ 102.74	$ 97.09
Company average	**$ 80.08**	$ 85.28	$ 67.96
Natural gas ($/Mcf) (1) (2)			
North America	**$ 2.36**	$ 3.36	$ 3.77
North Sea	**$ 4.11**	$ 4.17	$ 3.56
Offshore Africa	**$ 9.85**	$ 12.79	$ 7.34
Company average	**$ 2.47**	$ 3.50	$ 3.83
Company average ($/BOE) (1) (2)	**$ 55.21**	$ 61.21	$ 51.33

(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 $74.27 per bbl for the first quarter of 2012, an increase of 19% compared to $62.21 per bbl for the first quarter of 2011 and a decrease of 8% compared to $81.02 per bbl for the fourth quarter of 2011. The increase in prices for the first quarter of 2012 compared to the first quarter of 2011 was primarily a result of higher benchmark WTI pricing, the narrowing WCS Heavy Differential and the impact of a weaker Canadian dollar relative to the US dollar. The decrease in prices relative to the fourth quarter of 2011 was due to a widening WCS Heavy Differential and the impact of a stronger Canadian dollar relative to the US dollar; partially offset by higher benchmark WTI pricing. The Company continues to focus on its crude oil blending marketing strategy, and in the first quarter of 2012 contributed approximately 152,000 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 upgrader refinery near Redwater, Alberta. In addition, the partnership has entered into a 30 year fee-for-service agreement to process bitumen supplied by the Company and the Government of Alberta under the Bitumen Royalty In Kind initiative. Project development is dependent upon completion of detailed engineering and final project sanction by the partnership and its partners and approval of the final tolls. Board sanction is currently targeted in 2012.

North America realized natural gas prices decreased 37% to average $2.36 per Mcf for the first quarter of 2012, compared to $3.77 per Mcf in the first quarter of 2011, and decreased 30% compared to $3.36 per Mcf for the fourth quarter of 2011. The decrease in natural gas prices from the comparable periods in 2011 was primarily due to lower NYMEX and AECO benchmark pricing related to the impact of strong supply from US shale projects and the effects of a warmer than normal winter.

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

(Quarterly Average)	**Mar 31 2012**	Dec 31 2011	Mar 31 2011
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 76.34**	$ 86.05	$ 76.57
Pelican Lake heavy crude oil ($/bbl)	**$ 74.16**	$ 81.64	$ 62.78
Primary heavy crude oil ($/bbl)	**$ 72.84**	$ 79.91	$ 59.62
Bitumen (thermal oil) ($/bbl)	**$ 74.76**	$ 78.38	$ 56.79
Natural gas ($/Mcf)	**$ 2.36**	$ 3.36	$ 3.77

(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 $117.03 per bbl for the first quarter of 2012, an increase of 14% from $102.51 per bbl for the first quarter of 2011, and 7% from $109.71 for the fourth quarter of 2011. The increase in realized crude oil prices in the North Sea for the first quarter of 2012 from the comparable periods in 2011 was primarily the result of higher Brent benchmark pricing and fluctuations in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 33% to average $128.94 per bbl for the first quarter of 2012 from $97.09 per bbl for the first quarter of 2011, and an increase of 26% from $102.74 per bbl for the fourth quarter of 2011. The increase in realized crude oil prices in Offshore Africa for the first quarter of 2012 from the comparable periods in 2011 was primarily the result of higher Brent benchmark pricing and the timing of liftings, together with the impact of fluctuations in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 13.75**	$ 17.10	$ 11.61
North Sea	**$ 0.30**	$ 0.23	$ 0.28
Offshore Africa	**$ 20.01**	$ 15.35	$ 8.66
Company average	**$ 13.08**	$ 15.53	$ 10.43
Natural gas ($/Mcf) [1]			
North America	**$ 0.03**	$ 0.15	$ 0.12
Offshore Africa	**$ 1.53**	$ 2.33	$ 0.97
Company average	**$ 0.05**	$ 0.18	$ 0.13
Company average ($/BOE) [1]	**$ 8.23**	$ 10.14	$ 6.87

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

North America

North America crude oil and natural gas royalties for the three months ended March 31, 2012 compared to the comparable periods in 2011 reflected benchmark commodity prices.

Crude oil and NGLs royalties averaged approximately 19% of product sales for the first quarter of 2012 and the first quarter of 2011 compared to 21% for the fourth quarter of 2011. Crude oil and NGLs royalties per bbl are anticipated to average 18% to 21% of product sales for 2012.

Natural gas royalties averaged approximately 1% of product sales for the first quarter of 2012, compared to 3% for the first quarter of 2011 and 4% for the fourth quarter of 2011. Natural gas royalties are anticipated to average 1% to 3% of product sales for 2012.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital costs, the status of payouts and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 16% for the first quarter of 2012 compared to 9% for the first quarter of 2011 and 18% for the fourth quarter of 2011. The increase in royalty rates from the first quarter of 2011 was due to payout of the Baobab field in May 2011 and higher crude oil prices during the year.

Offshore Africa royalty rates are anticipated to average 13% to 15% of product sales for 2012.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 15.40**	$ 14.32	$ 12.28
North Sea	**$ 36.53**	$ 36.45	$ 30.46
Offshore Africa	**$ 12.17**	$ 22.16	$ 19.13
Company average	**$ 16.78**	$ 16.85	$ 14.30
Natural gas ($/Mcf) (1)			
North America	**$ 1.33**	$ 1.12	$ 1.16
North Sea	**$ 3.98**	$ 3.51	$ 2.65
Offshore Africa	**$ 1.76**	$ 2.52	$ 1.25
Company average	**$ 1.34**	$ 1.15	$ 1.17
Company average ($/BOE) (1)	**$ 13.43**	$ 13.12	$ 11.59

(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 2012 increased 25% to $15.40 per bbl from $12.28 per bbl for the first quarter of 2011 and increased 8% from $14.32 per bbl for the fourth quarter of 2011. The increase in production expense per barrel from the comparable periods in 2011 was a result of higher overall service costs relating to heavy crude oil production and seasonality. North America crude oil and NGLs production expense is anticipated to average $11.00 to $13.00 per bbl for 2012.

North America natural gas production expense for the first quarter of 2012 increased 15% to $1.33 per Mcf from $1.16 per Mcf for the first quarter of 2011, and increased 19% from $1.12 per Mcf for the fourth quarter of 2011. Natural gas production expense increased from the comparable periods in 2011 due to the impact of normal seasonal costs associated with winter access and colder weather and acquisitions of natural gas producing properties that have higher operating costs per Mcf than the Company's existing properties. These acquisitions closed late in the fourth quarter of 2011 and costs are expected to decline once the acquisitions are fully integrated into the Company's operations. North America natural gas production expense is anticipated to average $1.10 to $1.20 per Mcf for 2012.

North Sea

North Sea crude oil production expense for the first quarter of 2012 increased 20% to $36.53 per bbl from $30.46 per bbl for the first quarter of 2011, and was comparable to $36.45 per bbl in the fourth quarter of 2011. Production expense increased on a per barrel basis from the comparable periods in 2011 due to lower production volumes on relatively fixed costs and increased fuel prices. North Sea crude oil production expense is anticipated to average $43.00 to $48.00 per bbl for 2012.

Offshore Africa

Offshore Africa crude oil production expense for the first quarter of 2012 averaged $12.17 per bbl, a decrease of 36% compared to $19.13 per bbl for the first quarter of 2011 and a decrease of 45% compared to $22.16 per bbl for the fourth quarter of 2011. Production expense decreased from the comparable periods in 2011 due to the timing of liftings from various fields, which have different cost structures. Offshore Africa crude oil production expense is anticipated to average $27.00 to $29.00 per bbl for 2012.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Expense ($ millions)	**$ 910**	$ 863	$ 824
$/BOE (1)	**$ 17.73**	$ 16.51	$ 16.33

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

Depletion, depreciation and amortization expense increased for the first quarter of 2012 from the comparable periods in 2011 due to higher production volumes in North America associated with heavy oil drilling and higher overall future development costs, partially offset by lower production volumes in the North Sea and Offshore Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Expense ($ millions)	**$ 29**	$ 28	$ 28
$/BOE (1)	**$ 0.56**	$ 0.54	$ 0.56

(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

The Company temporarily suspended synthetic crude oil production at Horizon on February 5, 2012 to complete unplanned maintenance on the fractionating unit in the primary upgrading facility. On March 13, 2012 the Company successfully and safely completed the unplanned maintenance on the fractionating unit.

PRODUCT PRICES AND ROYALTIES – OIL SANDS MINING AND UPGRADING

($/bbl) [1]	Three Months Ended **Mar 31 2012**	Dec 31 2011	Mar 31 2011
SCO sales price [2]	**$ 97.09**	$ 103.16	$ 82.93
Bitumen value for royalty purposes [3]	**$ 64.37**	$ 69.91	$ 51.13
Bitumen royalties [4]	**$ 5.16**	$ 4.21	$ 4.14

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period during suspension of production.
(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 $97.09 per bbl for the first quarter of 2012, an increase of 17% compared to $82.93 per bbl for the first quarter of 2011, and a decrease of 6% compared to $103.16 per bbl in the fourth quarter of 2011, reflecting the relative changes in WTI and Brent benchmark pricing.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

($ millions)	Three Months Ended **Mar 31 2012**	Dec 31 2011	Mar 31 2011
Cash costs	**$ 346**	$ 344	$ 256
Less: costs incurred during the period of suspension of production	**(154)**	–	(209)
Adjusted cash costs	**$ 192**	$ 344	$ 47
Adjusted cash costs, excluding natural gas costs	**$ 177**	$ 316	$ 42
Adjusted natural gas costs	**15**	28	5
Adjusted cash production costs	**$ 192**	$ 344	$ 47

($/bbl) [1]	Three Months Ended **Mar 31 2012**	Dec 31 2011	Mar 31 2011
Adjusted cash costs, excluding natural gas costs	**$ 42.70**	$ 33.11	$ 41.38
Adjusted natural gas costs	**3.54**	2.93	4.31
Adjusted cash production costs	**$ 46.24**	$ 36.04	$ 45.69
Sales (bbl/d)	**45,741**	103,710	11,376

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period during suspension of production.

Adjusted cash production costs for the first quarter of 2012 averaged $46.24 per bbl, comparable to $45.69 per bbl for the first quarter of 2011, and an increase of 28% compared to $36.04 per bbl in the fourth quarter of 2011. The increase in cash production costs per bbl from the fourth quarter of 2011 was primarily due to the impact of the ramp up of production related to the repair of the fractionating unit during the first quarter of 2012.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions)	Three Months Ended **Mar 31 2012**	Dec 31 2011	Mar 31 2011
Depletion, depreciation and amortization	**$ 63**	$ 133	$ 23
Less: depreciation incurred during the period of suspension of production	**(6)**	–	(10)
Adjusted depletion, depreciation and amortization	**$ 57**	$ 133	$ 13
$/bbl [1]	**$ 13.81**	$ 13.91	$ 12.37

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period during suspension of production.

Depletion, depreciation and amortization expense for the first quarter of 2012 increased compared to the first quarter of 2011 due to higher production volumes. The decrease from the fourth quarter of 2011 was due to lower production volumes resulting from the temporary suspension of production during the first quarter of 2012.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions)	Three Months Ended **Mar 31 2012**	Dec 31 2011	Mar 31 2011
Expense	**$ 8**	$ 5	$ 5
$/bbl [1]	**$ 1.91**	$ 0.52	$ 4.84

(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

($ millions)	Three Months Ended **Mar 31 2012**	Dec 31 2011	Mar 31 2011
Revenue	**$ 21**	$ 22	$ 22
Production expense	**7**	7	7
Midstream cash flow	**14**	15	15
Depreciation	**2**	2	2
Segment earnings before taxes	**$ 12**	$ 13	$ 13

Midstream operating results were consistent with the comparable periods.

ADMINISTRATION EXPENSE

($ millions)	Three Months Ended Mar 31 2012	Dec 31 2011	Mar 31 2011
Expense	**$ 65**	$ 47	$ 54
$/BOE [(1)]	**$ 1.17**	$ 0.76	$ 1.05

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

Administration expense for the first quarter of 2012 increased from the comparable periods in 2011 primarily due to higher staffing related costs.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Mar 31 2012	Dec 31 2011	Mar 31 2011
(Recovery) expense	**$ (107)**	$ 207	$ 128

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

The Company recorded a $107 million share-based compensation recovery for the three months ended March 31, 2012, primarily as a result of remeasurement of the fair value of outstanding stock options at the end of the period related to a decrease in the Company's share price, offset by normal course graded vesting of stock options granted in prior periods and the impact of vested stock options exercised or surrendered during the period. For the three months ended March 31, 2012, a $7 million recovery was recognized in respect of capitalized share-based compensation to Oil Sands Mining and Upgrading (December 31, 2011 – $ nil; March 31, 2011 – $11 million capitalized).

For the three months ended March 31, 2012, the Company paid $7 million for stock options surrendered for cash settlement (December 31, 2011 – $ 2 million; March 31, 2011 – $10 million).

INTEREST AND OTHER FINANCING COSTS

($ millions, except per BOE amounts)	Three Months Ended Mar 31 2012	Dec 31 2011	Mar 31 2011
Expense, gross	**$ 114**	$ 102	$ 105
Less: capitalized interest	**18**	19	11
Expense, net	**$ 96**	$ 83	$ 94
$/BOE [(1)]	**$ 1.72**	$ 1.35	$ 1.83
Average effective interest rate	**4.8%**	4.7%	4.8%

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

Gross interest and other financing costs for the first quarter of 2012 increased compared to the first quarter of 2011 due to higher average US dollar debt levels and the impact of a weaker Canadian dollar related to US dollar interest, partially offset by lower average interest rates on fixed rate debt. Gross interest and other financing costs increased compared to the fourth quarter of 2011 due to higher interest rates and interest income recoveries recognized in the fourth quarter of 2011, partially offset by lower average debt levels and a stronger Canadian dollar. Capitalized interest for the three months ended March 31, 2012 increased from the first quarter of 2011 relating to Horizon and the Kirby Project, and was comparable to the fourth quarter of 2011.

The Company's average effective interest rate for the first quarter of 2012 was consistent to the comparable periods in 2011.

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 2012**	Dec 31 2011	Mar 31 2011
Crude oil and NGLs financial instruments	**$ 9**	$ 27	$ 27
Foreign currency contracts and interest rate swaps	**85**	(7)	43
Realized loss	**$ 94**	$ 20	$ 70
Crude oil and NGLs financial instruments	**$ 96**	$ 5	$ 67
Foreign currency contracts and interest rate swaps	**(36)**	53	(13)
Unrealized loss	**$ 60**	$ 58	$ 54
Net loss	**$ 154**	$ 78	$ 124

Complete details related to outstanding derivative financial instruments at March 31, 2012 are disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

The Company recorded a net unrealized loss of $60 million ($40 million after-tax) on its risk management activities for the three months ended March 31, 2012 (December 31, 2011 – unrealized loss of $58 million; $50 million after-tax; March 31, 2011 – unrealized loss of $54 million; $39 million after-tax), primarily due to changes in crude oil forward pricing and the reversal of prior period unrealized gains and losses related to crude oil and foreign currency contracts.

FOREIGN EXCHANGE

	Three Months Ended		
($ millions)	**Mar 31 2012**	Dec 31 2011	Mar 31 2011
Net realized loss	**$ 6**	$ 11	$ 22
Net unrealized gain(1)	**(60)**	(117)	(89)
Net gain	**$ (54)**	$ (106)	$ (67)

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

The net realized foreign exchange loss for the three months ended March 31, 2012 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the three months ended March 31, 2012 was primarily related 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, 2012– unrealized loss of $42 million; December 31, 2011 – unrealized loss of $43 million; March 31, 2011 – unrealized loss of $48 million). The Canadian dollar ended the first quarter at US$1.0009 (December 31, 2011 – US$0.9833; March 31, 2011 – US$1.0290).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Mar 31 2012	Dec 31 2011	Mar 31 2011
North America [1]	**$ 113**	$ 119	$ 91
North Sea	**45**	84	46
Offshore Africa	**36**	50	20
PRT expense – North Sea	**31**	39	8
Other taxes	**6**	7	6
Current income tax	**231**	299	171
Deferred income tax (recovery) expense	**(48)**	157	43
Deferred PRT (recovery) expense – North Sea	**(4)**	(13)	10
Deferred income tax (recovery) expense	**(52)**	144	53
	179	443	224
Income tax rate and other legislative changes [2]	**–**	–	(104)
	$ 179	$ 443	$ 120
Effective income tax rate on adjusted net earnings from operations [3]	**35.6%**	30.1%	32.7%

(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 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%.

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

The increase in the effective income tax rate on adjusted net earnings in the first quarter of 2012 from the fourth quarter of 2011 was primarily due to the impact of the temporary suspension of production at Horizon due to unplanned maintenance on the fractionating unit.

During the fourth quarter of 2011, the Canadian Federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of the corporate partners based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five-year transition provision and has no impact on net earnings.

In its 2012 budget, the UK government confirmed its intention to restrict tax relief on decommissioning expenditures to 50% for non-PRT fields and 75% for PRT fields. The legislation is expected to be substantively enacted in the second or third quarter of 2012. This tax change will result in a deferred tax charge currently estimated at $56 million.

During the first quarter of 2011, the UK government enacted an increase to the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate 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.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

For 2012, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $600 million to $700 million in Canada and $275 million to $375 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Mar 31 2012**	Dec 31 2011	Mar 31 2011
Exploration and Evaluation			
Net expenditures	**$ 208**	$ 112	$ 74
Property, Plant and Equipment			
Net property acquisitions	**38**	396	224
Well drilling, completion and equipping	**499**	585	572
Production and related facilities	**505**	480	416
Capitalized interest and other [2]	**30**	26	20
Net expenditures	**1,072**	1,487	1,232
Total Exploration and Production	**1,280**	1,599	1,306
Oil Sands Mining and Upgrading			
Horizon Phases 2/3 construction costs	**192**	150	90
Sustaining capital	**37**	44	24
Turnaround costs	**2**	–	55
Capitalized interest and other [2]	**3**	33	20
Total Oil Sands Mining and Upgrading	**234**	227	189
Horizon coker rebuild and collateral damage costs [3]	**–**	15	126
Midstream	**1**	–	3
Abandonments [4]	**76**	66	64
Head office	**5**	2	6
Total net capital expenditures	**$ 1,596**	$ 1,909	$ 1,694
By segment			
North America	**$ 1,223**	$ 1,546	$ 1,232
North Sea	**54**	71	41
Offshore Africa	**3**	(18)	33
Oil Sands Mining and Upgrading	**234**	242	315
Midstream	**1**	–	3
Abandonments [4]	**76**	66	64
Head office	**5**	2	6
Total	**$ 1,596**	$ 1,909	$ 1,694

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

(2) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.

(3) During 2011, the Company recognized $393 million of property damage insurance recoveries (see note 7 to the interim consolidated financial statements), offsetting the costs incurred related to the coker rebuild and collateral damage costs.

(4) 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 areas. 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 owning associated 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, 2012 were $1,596 million compared to $1,694 million for the three months ended March 31, 2011 and $1,909 million for the fourth quarter of 2011.

The decrease in capital expenditures for the first quarter of 2012 from the comparative periods in 2011 was due to lower property acquisitions and lower well drilling and completion expenditures related to the Company's drilling program.

Drilling Activity (number of wells)

	Three Months Ended		
	Mar 31 2012	Dec 31 2011	Mar 31 2011
Net successful natural gas wells	**19**	27	25
Net successful crude oil wells (1)	**278**	330	279
Dry wells	**6**	17	16
Stratigraphic test / service wells	**584**	112	501
Total	**887**	486	821
Success rate (excluding stratigraphic test / service wells)	**98%**	95%	95%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 82% of the total capital expenditures for the three months ended March 31, 2012 compared to approximately 77% for the three months ended March 31, 2011.

During the first quarter of 2012, the Company targeted 19 net natural gas wells, including 9 wells in Northeast British Columbia and 10 wells in Northwest Alberta. The Company also targeted 284 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 207 primary heavy crude oil wells, 1 Pelican Lake heavy crude oil well, 5 light crude oil wells and 43 bitumen (thermal oil) wells were drilled. Another 28 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall Primrose thermal production for the first quarter of 2012 averaged approximately 80,000 bbl/d, compared to approximately 98,000 bbl/d for the first quarter of 2011 and approximately 78,000 bbl/d for the fourth quarter of 2011. Production volumes were in line with expectations due to the cyclic nature of thermal production at Primrose. As part of the phased expansion of its in situ Oil Sands assets, the Company is continuing to develop its Primrose thermal projects. Additional pad drilling was completed and drilled on budget, with these wells coming on production in 2012.

The next planned phase of the Company's in situ oil sands assets expansion is the Kirby South Phase 1 Project. 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. Drilling has been completed on the third of seven pads and has commenced on the fourth pad.

Development of the tertiary recovery conversion projects at Pelican Lake continued and one horizontal well was drilled during the quarter. Pelican Lake production averaged approximately 39,000 bbl/d for the first quarter of 2012 and the first quarter of 2011 compared to 40,000 bbl/d in the fourth quarter of 2011.

For the second quarter of 2012, the Company's overall planned drilling activity in North America is expected to be 182 net crude oil wells and 3 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 efforts in the first quarter of 2012 were focused on field construction activities associated with the butane treatment and sulphur recovery units, engineering related to the coker expansion, extraction and froth treatment plants and securing key contracts for hydrogen and extraction trains 3 and 4. Final commissioning of the third ore preparation plant and associated hydro-transport was completed in January 2012.

In 2011, the Company recognized an asset impairment provision in the Oil Sands Mining and Upgrading segment of $396 million, net of accumulated depletion and amortization, related to the property damage resulting from a fire in the Horizon primary upgrading coking plant. The Company also recorded property damage insurance recoveries of $393 million and business interruption insurance recoveries of $333 million in 2011. In the first quarter of 2012, upon final settlement of its insurance claims, all outstanding insurance proceeds were collected.

North Sea

In December 2011, the Banff FPSO and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended. The FPSO and associated floating storage unit were subsequently removed from the field. All personnel on board the FPSO were safe and accounted for. The extent of the damage, including associated costs and timing of returning to the field, is currently being assessed.

In March 2011, the UK government 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, the Company's development activities in 2011 in the North Sea were reduced. The Company is continuing to high grade all North Sea prospects for potential development opportunities in 2012 and future years.

Offshore Africa

During the fourth quarter of 2011, the Company sanctioned an 8 well drilling program at the Espoir field in Côte d'Ivoire. Preparations are ongoing, targeting commencement of drilling operations in late 2012.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Mar 31 2012**	Dec 31 2011	Mar 31 2011
Working capital (deficit) (1)	**$ (1,304)**	$ (894)	$ (1,657)
Long-term debt (2) (3)	**$ 8,241**	$ 8,571	$ 8,468
Share capital	**$ 3,674**	$ 3,507	$ 3,394
Retained earnings	**19,656**	19,365	17,158
Accumulated other comprehensive loss	**59**	26	43
Shareholders' equity	**$ 23,389**	$ 22,898	$ 20,595
Debt to book capitalization (3) (4)	**26%**	27%	29%
Debt to market capitalization (3) (5)	**19%**	17%	14%
After-tax return on average common shareholders' equity (6)	**14%**	12%	5%
After-tax return on average capital employed (7)	**11%**	10%	5%

(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.

(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.

(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.

At March 31, 2012, 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 and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's December 31, 2011 annual MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon 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 ongoing 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. At March 31, 2012, the Company had $4,056 million of available credit under its bank credit facilities.

In the fourth quarter of 2011, 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 2013. If issued, these securities will bear interest as determined at the date of issuance. The Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus filed in the fourth quarter of 2011 that allows for the issue of US dollar debt securities in the United States until November 2013. If issued, these securities will bear interest as determined at the date of issuance.

Long-term debt was $8,241 million at March 31, 2012, resulting in a debt to book capitalization ratio of 26% (December 31, 2011 – 27%; March 31, 2011 – 29%). 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, or 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. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. The Company has hedged a portion of its crude oil production for 2012 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, 2012 are discussed in note 5 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedging policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This policy 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 policy, the purchase of put options is in addition to the above parameters. As at May 3, 2012, approximately 50% of currently forecasted 2012 crude oil volumes were hedged using collars and puts. Further details related to the Company's commodity related derivative financial instruments outstanding at March 31, 2012 are discussed in note 13 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at March 31, 2012, there were 1,100,118,000 common shares outstanding and 68,433,000 stock options outstanding. As at May 2, 2012, the Company had 1,099,728,000 common shares outstanding and 66,029,000 stock options outstanding.

On March 6, 2012, the Company's Board of Directors approved an increase in the annual dividend to be paid by the Company to $0.42 per common share for 2012. The increase represents an approximately 17% increase from 2011, 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.

In April 2012, 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 9, 2012 and ending April 8, 2013, up to 55,027,447 common shares.

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 of the Company outstanding at March 25, 2011.

As at March 31, 2012, 692,200 common shares (December 31, 2011 - 3,071,100 common shares) had been purchased for cancellation at a weighted average price of $33.11 per common share (December 31, 2011 - $33.68 per common share), for a total cost of $23 million (December 31, 2011 - $104 million). Subsequent to March 31, 2012, the Company purchased 521,100 common shares at a weighted average price of $32.21 per common share for a total cost of $17 million.

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, 2012, no entities were consolidated under the Standing Interpretations Committee ("SIC") 12, "Consolidation – Special Purpose Entities". The following table summarizes the Company's commitments as at March 31, 2012:

($ millions)	2012	2013	2014	2015	2016	Thereafter
Product transportation and pipeline	$ 182	$ 211	$ 200	$ 187	$ 124	$ 888
Offshore equipment operating leases	$ 87	$ 99	$ 98	$ 81	$ 52	$ 117
Long-term debt (1)	$ 349	$ 800	$ 849	$ 989	$ 250	$ 5,046
Interest and other financing costs (2)	$ 305	$ 393	$ 373	$ 328	$ 315	$ 4,033
Office leases	$ 23	$ 33	$ 34	$ 32	$ 33	$ 304
Other	$ 221	$ 160	$ 90	$ 24	$ 2	$ 8

(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, 2012.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is a 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.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

For the impact of new accounting standards, refer to the MD&A and the audited consolidated financial statements for the year ended December 31, 2011.

CRITICAL ACCOUNTING ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting policies is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2011.

Consolidated Balance Sheets

As at (millions of Canadian dollars, unaudited)	Note	Mar 31 2012	Dec 31 2011
ASSETS			
Current assets			
Cash and cash equivalents		**$ 13**	$ 34
Accounts receivable		**1,346**	2,077
Inventory		**671**	550
Prepaids and other		**127**	120
		2,157	2,781
Exploration and evaluation assets	2	**2,644**	2,475
Property, plant and equipment	3	**41,959**	41,631
Other long-term assets	4	**368**	391
		$ 47,128	$ 47,278
LIABILITIES			
Current liabilities			
Accounts payable		**$ 526**	$ 526
Accrued liabilities		**2,298**	2,347
Current income tax liabilities		**277**	347
Current portion of long-term debt	5	**1,151**	359
Current portion of other long-term liabilities	6	**360**	455
		4,612	4,034
Long-term debt	5	**7,090**	8,212
Other long-term liabilities	6	**3,880**	3,913
Deferred income tax liabilities		**8,157**	8,221
		23,739	24,380
SHAREHOLDERS' EQUITY			
Share capital	9	**3,674**	3,507
Retained earnings		**19,656**	19,365
Accumulated other comprehensive income	10	**59**	26
		23,389	22,898
		$ 47,128	$ 47,278

Commitments and contingencies (note 14).

Approved by the Board of Directors on May 3, 2012

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Mar 31 2012	Mar 31 2011
Product sales		**$ 3,971**	$ 3,302
Less: royalties		**(444)**	(351)
Revenue		**3,527**	2,951
Expenses			
Production		**1,038**	845
Transportation and blending		**717**	621
Depletion, depreciation and amortization	3	**975**	849
Administration		**65**	54
Share-based compensation	6	**(107)**	128
Asset retirement obligation accretion	6	**37**	33
Interest and other financing costs		**96**	94
Risk management activities	13	**154**	124
Foreign exchange gain		**(54)**	(67)
Horizon asset impairment provision	7	**–**	396
Insurance recovery – property damage	7	**–**	(396)
		2,921	2,681
Earnings before taxes		**606**	270
Current income tax expense	8	**231**	171
Deferred income tax (recovery) expense	8	**(52)**	53
Net earnings		**$ 427**	$ 46
Net earnings per common share			
Basic	12	**$ 0.39**	$ 0.04
Diluted	12	**$ 0.39**	$ 0.04

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2012	Mar 31 2011
Net earnings	**$ 427**	$ 46
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized income during the period, net of taxes of $4 million (2011 – $3 million)	**24**	18
Reclassification to net earnings, net of taxes of $nil (2011 – $4 million)	**1**	11
	25	29
Foreign currency translation adjustment		
Translation of net investment	**8**	5
Other comprehensive income, net of taxes	**33**	34
Comprehensive income	**$ 460**	$ 80

Consolidated Statements of Changes in Equity

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Mar 31 2012**	Mar 31 2011
Share capital	9		
Balance – beginning of period		**$ 3,507**	$ 3,147
Issued upon exercise of stock options		**131**	162
Previously recognized liability on stock options exercised for common shares		**38**	85
Purchase of common shares under Normal Course Issuer Bid		**(2)**	–
Balance – end of period		**3,674**	3,394
Retained earnings			
Balance – beginning of period		**19,365**	17,212
Net earnings		**427**	46
Purchase of common shares under Normal Course Issuer Bid	9	**(21)**	–
Dividends on common shares	9	**(115)**	(100)
Balance – end of period		**19,656**	17,158
Accumulated other comprehensive income	10		
Balance – beginning of period		**26**	9
Other comprehensive income, net of taxes		**33**	34
Balance – end of period		**59**	43
Shareholders' equity		**$ 23,389**	$ 20,595

Consolidated Statements of Cash Flows

		Three Months Ended	
(millions of Canadian dollars, unaudited)	Note	**Mar 31 2012**	Mar 31 2011
Operating activities			
Net earnings		**$ 427**	$ 46
Non-cash items			
Depletion, depreciation and amortization		**975**	849
Share-based compensation		**(107)**	128
Asset retirement obligation accretion		**37**	33
Unrealized risk management loss		**60**	54
Unrealized foreign exchange gain		**(60)**	(89)
Deferred income tax (recovery) expense		**(52)**	53
Horizon asset impairment provision	7	**–**	396
Insurance recovery – property damage	7	**–**	(396)
Other		**23**	(29)
Abandonment expenditures		**(76)**	(64)
Net change in non-cash working capital		**230**	264
		1,457	1,245
Financing activities			
(Repayment) issue of bank credit facilities, net		**(207)**	128
Issue of common shares on exercise of stock options		**131**	162
Purchase of common shares under Normal Course Issuer Bid		**(23)**	–
Dividends on common shares		**(99)**	(82)
Net change in non-cash working capital		**(3)**	–
		(201)	208
Investing activities			
Expenditures on exploration and evaluation assets and property, plant and equipment		**(1,520)**	(1,630)
Investment in other long-term assets		**–**	(346)
Net change in non-cash working capital		**243**	551
		(1,277)	(1,425)
(Decrease) increase in cash and cash equivalents		**(21)**	28
Cash and cash equivalents – beginning of period		**34**	22
Cash and cash equivalents – end of period		**$ 13**	$ 50
Interest paid		**$ 133**	$ 147
Income taxes paid		**$ 265**	$ 282

(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

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.

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.

These interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34, "Interim Financial Reporting", following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2011. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2011.

2. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2011	$ 2,442	$ –	$ 33	$ –	$ 2,475
Additions	**208**	**–**	**–**	**–**	**208**
Transfers to property, plant and equipment	**(39)**	**–**	**–**	**–**	**(39)**
At March 31, 2012	**$ 2,611**	**$ –**	**$ 33**	**$ –**	**$ 2,644**

3. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2011	$ 46,120	$ 4,147	$ 3,044	$ 15,211	$ 298	$ 234	$ 69,054
Additions	**1,028**	**56**	**3**	**236**	**1**	**5**	**1,329**
Transfers from E&E assets	**39**	**–**	**–**	**–**	**–**	**–**	**39**
Disposals/ derecognitions	**–**	**–**	**–**	**(1)**	**–**	**–**	**(1)**
Foreign exchange adjustments and other	**–**	**(73)**	**(52)**	**–**	**–**	**–**	**(125)**
At March 31, 2012	**$ 47,187**	**$ 4,130**	**$ 2,995**	**$ 15,446**	**$ 299**	**$ 239**	**$ 70,296**
Accumulated depletion and depreciation							
At December 31, 2011	$ 21,721	$ 2,512	$ 2,152	$ 776	$ 96	$ 166	$ 27,423
Expense	**796**	**83**	**28**	**63**	**2**	**3**	**975**
Disposals/ derecognitions	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Foreign exchange adjustments and other	**–**	**(48)**	**(25)**	**12**	**–**	**–**	**(61)**
At March 31, 2012	**$ 22,517**	**$ 2,547**	**$ 2,155**	**$ 851**	**$ 98**	**$ 169**	**$ 28,337**
Net book value							
- at March 31, 2012	**$ 24,670**	**$ 1,583**	**$ 840**	**$ 14,595**	**$ 201**	**$ 70**	**$ 41,959**
- at December 31, 2011	$ 24,399	$ 1,635	$ 892	$ 14,435	$ 202	$ 68	$ 41,631

Development projects not subject to depletion	
At March 31, 2012	$ 1,050
At December 31, 2011	$ 1,443

The Company acquired a number of producing crude oil and natural gas assets in the North America Exploration and Production segment for total cash consideration of $38 million during the period ended March 31, 2012 (year ended December 31, 2011 – $1,012 million), net of associated asset retirement obligations of $3 million (year ended December 31, 2011 – $79 million). Interests in jointly controlled assets were acquired with full tax basis. No working capital or debt obligations were assumed.

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 period ended March 31, 2012, pre-tax interest of $18 million was capitalized to property, plant and equipment (March 31, 2011 – $11 million) using a capitalization rate of 4.8% (March 31, 2011 – 4.8%).

4. OTHER LONG-TERM ASSETS

		Mar 31 2012		Dec 31 2011
Investment in North West Redwater Partnership	$	321	$	321
Other		47		70
	$	368	$	391

Other long-term assets include a $321 million investment in the 50% owned North West Redwater Partnership ("Redwater"), of which $66 million was payable to Redwater at March 31, 2012 to fund project development. The investment is accounted for using the equity method. Redwater has entered into an agreement to construct and operate a bitumen upgrader and refinery, which targets to process bitumen for the Company and the Government of Alberta under a 30 year fee-for-service contract. Project development is dependent upon completion of detailed engineering and final project sanction by Redwater and its partners, and approval of the final tolls.

5. LONG-TERM DEBT

		Mar 31 2012		Dec 31 2011
Canadian dollar denominated debt				
Bank credit facilities	$	589	$	796
Medium-term notes		800		800
		1,389		1,596
US dollar denominated debt				
US dollar debt securities (US$6,900 million)		6,894		7,017
Less: original issue discount on US dollar debt securities (1)		(21)		(21)
		6,873		6,996
Fair value impact of interest rate swaps on US dollar debt securities (2)		29		31
		6,902		7,027
Long-term debt before transaction costs		8,291		8,623
Less: transaction costs (1) (3)		(50)		(52)
		8,241		8,571
Less: current portion (1) (2)		1,151		359
	$	7,090	$	8,212

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

(2) The carrying amounts of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 were adjusted by $29 million (December 2011 – $31 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, 2012, the Company had in place unsecured bank credit facilities of $4,724 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $3,000 million maturing June 2015;
- 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.

Each of the $3,000 million and $1,500 million facilities is 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 may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

The Company's weighted average interest rate on bank credit facilities outstanding as at March 31, 2012, was 2.2% (March 31, 2011 – 1.4%), and on long-term debt outstanding for the period ended March 31, 2012 was 4.8% (March 31, 2011 – 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $464 million, including $110 million related to Horizon and $272 million related to North Sea operations, were outstanding at March 31, 2012.

Medium-Term Notes

During the fourth quarter of 2011, 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 2013. If issued, these securities will bear interest as determined at the date of issuance.

US Dollar Debt Securities

The Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus filed in the fourth quarter of 2011 that allows for the issue of US dollar debt securities in the United States until November 2013. If issued, these securities will bear interest as determined at the date of issuance.

6. OTHER LONG-TERM LIABILITIES

	Mar 31 2012	Dec 31 2011
Asset retirement obligations	**$ 3,538**	$ 3,577
Share-based compensation	**273**	432
Risk management (note 13)	**347**	274
Other	**82**	85
	4,240	4,368
Less: current portion	**360**	455
	$ 3,880	$ 3,913

Asset retirement obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.6% (December 31, 2011 – 4.6%). A reconciliation of the discounted asset retirement obligations is as follows:

	Mar 31 2012	Dec 31 2011
Balance – beginning of period	**$ 3,577**	$ 2,624
Liabilities incurred	**10**	12
Liabilities acquired	**3**	79
Liabilities settled	**(76)**	(213)
Asset retirement obligation accretion	**37**	130
Revision of estimates	**3**	924
Foreign exchange	**(16)**	21
Balance – end of period	**$ 3,538**	$ 3,577

Share-based compensation

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock 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 stock options are surrendered for cash settlement.

	Mar 31 2012	Dec 31 2011
Balance – beginning of period	**$ 432**	$ 663
Share-based compensation recovery	**(107)**	(102)
Cash payment for stock options surrendered	**(7)**	(14)
Transferred to common shares	**(38)**	(115)
Capitalized to (recovered from) Oil Sands Mining and Upgrading	**(7)**	–
Balance – end of period	**273**	432
Less: current portion	**230**	384
	$ 43	$ 48

7. HORIZON ASSET IMPAIRMENT PROVISION AND INSURANCE RECOVERY

In 2011, the Company recognized an asset impairment provision in the Oil Sands Mining and Upgrading segment of $396 million, net of accumulated depletion and amortization, related to the property damage resulting from a fire in the Horizon primary upgrading coking plant. The Company also recorded final property damage insurance recoveries of $393 million and business interruption insurance recoveries of $333 million in 2011. In the first quarter of 2012, upon final settlement of its insurance claims, all outstanding insurance proceeds were collected.

8. INCOME TAXES

The provision for income tax is as follows:

	Three Months Ended	
	Mar 31 2012	Mar 31 2011
Current corporate income tax – North America	**$ 113**	$ 91
Current corporate income tax – North Sea	**45**	46
Current corporate income tax – Offshore Africa	**36**	20
Current PRT(1) expense – North Sea	**31**	8
Other taxes	**6**	6
Current income tax expense	**231**	171
Deferred corporate income tax (recovery) expense	**(48)**	43
Deferred PRT(1) (recovery) expense – North Sea	**(4)**	10
Deferred income tax (recovery) expense	**(52)**	53
Income tax expense	**$ 179**	$ 224

(1) Petroleum Revenue Tax.

During 2011, the Canadian Federal government enacted legislation to implement several taxation changes. These changes include a requirement that, beginning in 2012, partnership income must be included in the taxable income of each corporate partner based on the tax year of the partner, rather than the fiscal year of the partnership. The legislation includes a five-year transition provision and has no impact on net earnings.

During the first quarter of 2011, the UK government enacted an increase to the supplementary income tax rate charged on profits from UK North Sea crude oil and natural gas production, increasing the combined corporate and supplementary income tax rate 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.

9. 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, 2012		
Issued common shares	**Number of shares** (thousands)		**Amount**
Balance – beginning of period	**1,096,460**	$	**3,507**
Issued upon exercise of stock options	**4,350**		**131**
Previously recognized liability on stock options exercised for common shares	**–**		**38**
Purchase of common shares under Normal Course Issuer Bid	**(692)**		**(2)**
Balance – end of period	**1,100,118**	$	**3,674**

Dividend Policy

On March 6, 2012, the Board of Directors set the regular quarterly dividend at $0.105 per common share (2011 – $0.09 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

The Company's Normal Course Issuer Bid announced in 2011 expired April 5, 2012. In April 2012, 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 twelve month period commencing April 9, 2012 and ending April 8, 2013, up to 55,027,447 common shares.

For the three months ended March 31, 2012, the Company purchased 692,200 common shares at a weighted average price of $33.11 per common share, for a total cost of $23 million. Retained earnings were reduced by $21 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2012, the Company purchased 521,100 common shares at a weighted average price of $32.21 per common share for a total cost of $17 million.

Stock Options

The following table summarizes information relating to stock options outstanding at March 31, 2012:

	Three Months Ended Mar 31, 2012		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**73,486**	**$**	**34.85**
Granted	**1,492**	**$**	**34.40**
Surrendered for cash settlement	**(710)**	**$**	**30.79**
Exercised for common shares	**(4,350)**	**$**	**30.23**
Forfeited	**(1,485)**	**$**	**37.40**
Outstanding – end of period	**68,433**	**$**	**35.12**
Exercisable – end of period	**21,955**	**$**	**32.56**

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.

10. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		Mar 31 2012		Mar 31 2011
Derivative financial instruments designated as cash flow hedges	**$**	**87**	$	62
Foreign currency translation adjustment		**(28)**		(19)
	$	**59**	$	43

11. 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 at 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, or 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, 2012, the ratio was below the target range at 26%.

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 2012		Dec 31 2011
Long-term debt [1]	**$**	**8,241**	$	8,571
Total shareholders' equity	**$**	**23,389**	$	22,898
Debt to book capitalization		**26%**		27%

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

12. NET EARNINGS PER COMMON SHARE

	Three Months Ended			
		Mar 31 2012		Mar 31 2011
Weighted average common shares outstanding – basic (thousands of shares)		**1,100,154**		1,093,685
Effect of dilutive stock options (thousands of shares)		**4,454**		11,992
Weighted average common shares outstanding – diluted (thousands of shares)		**1,104,608**		1,105,677
Net earnings	**$**	**427**	$	46
Net earnings per common share – basic	**$**	**0.39**	$	0.04
– diluted	**$**	**0.39**	$	0.04

13. FINANCIAL INSTRUMENTS

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

	Mar 31, 2012				
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	$ 1,346	$ –	$ –	$ –	$ 1,346
Accounts payable	–	–	–	(526)	(526)
Accrued liabilities	–	–	–	(2,298)	(2,298)
Other long-term liabilities	–	(98)	(249)	(73)	(420)
Long-term debt (1)	–	–	–	(8,241)	(8,241)
	$ 1,346	$ (98)	$ (249)	$ (11,138)	$ (10,139)

	Dec 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	$ 2,077	$ –	$ –	$ –	$ 2,077
Accounts payable	–	–	–	(526)	(526)
Accrued liabilities	–	–	–	(2,347)	(2,347)
Other long-term liabilities	–	(38)	(236)	(75)	(349)
Long-term debt (1)	–	–	–	(8,571)	(8,571)
	$ 2,077	$ (38)	$ (236)	$ (11,519)	$ (9,716)

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

The carrying amount 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 other long-term liabilities and fixed rate long-term debt are outlined below:

	Mar 31, 2012		
	Carrying amount	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term liabilities	$ (347)	$ –	$ (347)
Fixed rate long-term debt (2) (3) (4)	(7,652)	(8,831)	–
	$ (7,999)	$ (8,831)	$ (347)

	Dec 31, 2011		
	Carrying amount	Fair value	
Asset (liability) [1]		Level 1	Level 2
Other long-term liabilities	$ (274)	$ –	$ (274)
Fixed rate long-term debt [2] [3] [4]	(7,775)	(9,120)	–
	$ (8,049)	$ (9,120)	$ (274)

(1) Excludes financial assets and liabilities where the carrying amount 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 amounts 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 $29 million (December 31, 2011 – $31 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, 2012**	Dec 31, 2011
Derivatives held for trading		
Crude oil price collars	**$ (65)**	$ (13)
Crude oil put options	**(44)**	–
Foreign currency forward contracts	**11**	(25)
Cash flow hedges		
Cross currency swaps	**(249)**	(236)
	$ (347)	$ (274)
Included within:		
Current portion of other long-term liabilities	**$ (106)**	$ (43)
Other long-term liabilities	**(241)**	(231)
	$ (347)	$ (274)

Ineffectiveness arising from cash flow hedges recognized in net earnings for the period ended March 31, 2012 resulted in a gain of $1 million (December 31, 2011 – loss of $2 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 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. 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:

Asset (liability)	**Three Months Ended Mar 31, 2012**	Year Ended Dec 31, 2011
Balance – beginning of period	**$ (274)**	$ (485)
Net cost of outstanding put options	**55**	–
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**(60)**	128
Foreign exchange	**(42)**	42
Other comprehensive income	**29**	41
	(292)	(274)
Add: put premium financing obligations (1)	**(55)**	–
Balance – end of period	**(347)**	(274)
Less: current portion	**(106)**	(43)
	$ (241)	$ (231)

(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 are reflected in the net risk management asset (liability).

Net losses from risk management activities were as follows:

	Three Months Ended	
	Mar 31 2012	Mar 31 2011
Net realized risk management loss	**$ 94**	$ 70
Net unrealized risk management loss	**60**	54
	$ 154	$ 124

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, 2012, the Company had the following derivative financial instruments outstanding to manage its commodity price risks:

Sales contracts

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars (1)	Apr 2012	–	Dec 2012	50,000 bbl/d	US$80.00	–	US$134.87	Brent
	Apr 2012	–	Dec 2012	50,000 bbl/d	US$80.00	–	US$136.06	Brent
Crude oil puts	Apr 2012	–	Dec 2012	100,000 bbl/d			US$80.00	WTI

(1) Subsequent to March 31, 2012, the Company entered into 50,000 bbl/d of US$80.00 - US$145.07 Brent collars for the period July 2012 to June 2013.

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

	Q2 2012	Q3 2012	Q4 2012
Cost ($ millions)	US$18	US$19	US$19

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.

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 periodically 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, 2012, the Company had no interest rate swap contracts outstanding.

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, 2012, 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 2012	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Apr 2012	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Apr 2012	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Apr 2012	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at March 31, 2012, were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at March 31, 2012, the Company had US$1,966 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, 2012, 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, 2012, the Company had net risk management assets of $nil with specific counterparties related to derivative financial instruments (December 31, 2011 – $nil).

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	$ 526	$ –	$ –	$ –
Accrued liabilities	$ 2,298	$ –	$ –	$ –
Risk management	$ 106	$ 43	$ 125	$ 73
Other long-term liabilities	$ 24	$ 15	$ 34	$ –
Long-term debt (1)	$ 1,149	$ –	$ 2,088	$ 5,046

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

14. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	Remaining 2012	2013	2014	2015	2016	Thereafter
Product transportation and pipeline	$ 182	$ 211	$ 200	$ 187	$ 124	$ 888
Offshore equipment operating leases	$ 87	$ 99	$ 98	$ 81	$ 52	$ 117
Office leases	$ 23	$ 33	$ 34	$ 32	$ 33	$ 304
Other	$ 221	$ 160	$ 90	$ 24	$ 2	$ 8

The Company is a 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.

15. SEGMENTED INFORMATION

	Exploration and Production							
(millions of Canadian dollars, unaudited)	North America Three months ended Mar 31		North Sea Three months ended Mar 31		Offshore Africa Three months ended Mar 31		Total Exploration and Production Three months ended Mar 31	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011
Segmented product sales	**3,058**	2,706	**279**	289	**217**	215	**3,554**	3,210
Less: royalties	**(388)**	(326)	**(1)**	(1)	**(34)**	(20)	**(423)**	(347)
Segmented revenue	**2,670**	2,380	**278**	288	**183**	195	**3,131**	2,863
Segmented expenses								
Production	**582**	458	**85**	86	**22**	42	**689**	586
Transportation and blending	**715**	612	**3**	4	**–**	1	**718**	617
Depletion, depreciation and amortization	**798**	703	**84**	68	**28**	53	**910**	824
Asset retirement obligation accretion	**21**	18	**7**	8	**1**	2	**29**	28
Realized risk management activities	**94**	70	**–**	–	**–**	–	**94**	70
Horizon asset impairment provision	**–**	–	**–**	–	**–**	–	**–**	–
Insurance recovery – property damage (note 7)	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**2,210**	1,861	**179**	166	**51**	98	**2,440**	2,125
Segmented earnings (loss) before the following	**460**	519	**99**	122	**132**	97	**691**	738
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 (recovery) expense								
Net earnings								

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading Three months ended Mar 31		Midstream Three months ended Mar 31		Inter-segment elimination and other Three months ended Mar 31		Total Three months ended Mar 31	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011
Segmented product sales	**414**	86	**21**	22	**(18)**	(16)	**3,971**	3,302
Less: royalties	**(21)**	(4)	**–**	–	**–**	–	**(444)**	(351)
Segmented revenue	**393**	82	**21**	22	**(18)**	(16)	**3,527**	2,951
Segmented expenses								
Production	**346**	256	**7**	7	**(4)**	(4)	**1,038**	845
Transportation and blending	**12**	16	**–**	–	**(13)**	(12)	**717**	621
Depletion, depreciation and amortization	**63**	23	**2**	2	**–**	–	**975**	849
Asset retirement obligation accretion	**8**	5	**–**	–	**–**	–	**37**	33
Realized risk management activities	**–**	–	**–**	–	**–**	–	**94**	70
Horizon asset impairment provision	**–**	396	**–**	–	**–**	–	**–**	396
Insurance recovery – property damage (note 7)	**–**	(396)	**–**	–	**–**	–	**–**	(396)
Total segmented expenses	**429**	300	**9**	9	**(17)**	(16)	**2,861**	2,418
Segmented earnings (loss) before the following	**(36)**	(218)	**12**	13	**(1)**	–	**666**	533
Non-segmented expenses								
Administration							**65**	54
Share-based compensation							**(107)**	128
Interest and other financing costs							**96**	94
Unrealized risk management activities							**60**	54
Foreign exchange gain							**(54)**	(67)
Total non-segmented expenses							**60**	263
Earnings before taxes							**606**	270
Current income tax expense							**231**	171
Deferred income tax (recovery) expense							**(52)**	53
Net earnings							**427**	46

Capital Expenditures [1]

	Period Ended					
	Mar 31, 2012			Mar 31, 2011		
	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 assets						
Exploration and Production						
North America	**$ 208**	**$ (39)**	**$ 169**	$ 74	$ (72)	$ 2
North Sea	**–**	**–**	**–**	–	(4)	(4)
Offshore Africa	**–**	**–**	**–**	–	–	–
	$ 208	**$ (39)**	**$ 169**	$ 74	$ (76)	$ (2)
Property, plant and equipment						
Exploration and Production						
North America	**$ 1,015**	**$ 52**	**$ 1,067**	$ 1,158	$ 75	$ 1,233
North Sea	**54**	**2**	**56**	41	4	45
Offshore Africa	**3**	**–**	**3**	33	–	33
	1,072	**54**	**1,126**	1,232	79	1,311
Oil Sands Mining and Upgrading[3][4]	**234**	**1**	**235**	315	(406)	(91)
Midstream	**1**	**–**	**1**	3	–	3
Head office	**5**	**–**	**5**	6	–	6
	$ 1,312	**$ 55**	**$ 1,367**	$ 1,556	$ (327)	$ 1,229

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

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

(3) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.

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

Segmented Assets

	Total Assets	
	Mar 31 2012	Dec 31 2011
Exploration and Production		
North America	**$ 28,770**	$ 28,554
North Sea	**1,722**	1,809
Offshore Africa	**1,094**	1,070
Other	**24**	23
Oil Sands Mining and Upgrading	**15,091**	15,433
Midstream	**357**	321
Head office	**70**	68
	$ 47,128	$ 47,278

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 2011. 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, 2012:

Interest coverage (times)	
Net earnings (1)	10.1x
Cash flow from operations (2)	17.8x

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

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time on Friday, May 4, 2012. 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, Thursday, May 10, 2012. To access the rebroadcast in North America, dial 1-800-408-3053. Those outside of North America, dial 001-905-694-9451. The pass code to use is 4985113.

WEBCAST

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

For further information, please contact:

CANADIAN NATURAL RESOURCES LIMITED

2500, 855 - 2nd Street S.W.

Calgary, Alberta

T2P 4J8

Telephone: (403) 514-7777
Facsimile: (403) 514-7888
Email: ir@cnrl.com
Website: www.cnrl.com

JOHN G. LANGILLE
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