PRESS RELEASE

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2011 FOURTH QUARTER AND YEAR END RESULTS CALGARY, ALBERTA – MARCH 8, 2012 – FOR IMMEDIATE RELEASE

Commenting on fourth quarter and year end results, Canadian Natural's Chairman, Allan Markin stated, "In Q4/11 we drilled a record number of crude oil wells and achieved record quarterly production of over 657,000 BOE/d. We increased our barrel of oil equivalent reserves on a Company Gross proved plus probable basis by 9% to 7.54 billion barrels, replacing 390% of our 2011 production. Our vast, diverse asset base continues to grow economically and will provide value and upside to shareholders for years to come."

John Langille, Vice-Chairman of Canadian Natural continued, "In Q4/11 we generated record cash flow from operations of approximately $2.2 billion representing an increase of 31% from Q4/10. We exited 2011 with improved balance sheet metrics, increased financial liquidity and a strengthened ability to create value for our shareholders through the development of our diverse asset base. This strong financial position contributed to the Company's decision to increase the quarterly dividend to $0.105 per common share, an approximate 17% increase over 2010 representing the twelfth consecutive year of increases for the Company."

Steve Laut, President of Canadian Natural concluded, "Canadian Natural's well balanced and diverse asset base, in combination with our ability to optimize capital allocation to maximize value, sets us apart from our peers. Canadian Natural's diverse production base allows us to withstand swings in commodity pricing and occasional production outages, while maintaining a strong balance sheet and ensuring cost effective development of our vast asset base. Although the current Horizon outage is significant for our oil sands mining area, on a company basis, the outage impacts full year production by less than 2%, highlighting the soundness of our strategy and the strength of our asset base.

The start up of Horizon is tracking to our original schedule of mid to late March and with our third Ore Preparation Plant ready for operations, we expect steady reliable production from Horizon going forward."

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended Dec 31 2011	Three Months Ended Sep 30 2011	Three Months Ended Dec 31 2010	Year Ended Dec 31 2011	Year Ended Dec 31 2010
Net earnings (loss)	**$ 832**	$ 836	$ (309)	**$ 2,643**	$ 1,673
Per common share - basic	**$ 0.76**	$ 0.76	$ (0.28)	**$ 2.41**	$ 1.54
- diluted	**$ 0.76**	$ 0.76	$ (0.28)	**$ 2.40**	$ 1.53
Adjusted net earnings from operations (1)	**$ 972**	$ 719	$ 585	**$ 2,540**	$ 2,444
Per common share - basic	**$ 0.89**	$ 0.65	$ 0.54	**$ 2.32**	$ 2.25
- diluted	**$ 0.88**	$ 0.65	$ 0.53	**$ 2.30**	$ 2.23
Cash flow from operations (2)	**$ 2,158**	$ 1,767	$ 1,652	**$ 6,547**	$ 6,333
Per common share - basic	**$ 1.97**	$ 1.62	$ 1.52	**$ 5.98**	$ 5.82
- diluted	**$ 1.96**	$ 1.60	$ 1.50	**$ 5.94**	$ 5.78
Capital expenditures, net of dispositions	**$ 1,909**	$ 1,406	$ 1,945	**$ 6,414**	$ 5,514
Daily production, before royalties					
Natural gas (MMcf/d)	**1,280**	1,252	1,252	**1,257**	1,243
Crude oil and NGLs (bbl/d)	**444,286**	403,900	438,835	**389,053**	424,985
Equivalent production (BOE/d) (3)	**657,599**	612,575	647,441	**598,526**	632,191

(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 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.

Fourth Quarter

- Average Q4/11 production growth over Q4/10 was driven by:
  - Primary heavy crude oil production increased approximately 20%
  - North America light crude oil and NGL production increased approximately 19%
  - Horizon synthetic crude oil ("SCO") production increased approximately 11%
  - Pelican Lake crude oil production increased approximately 7%
- Canadian Natural ("the Company") achieved record total crude oil and NGLs production of 444,286 bbl/d for Q4/11. Q4/11 crude oil production volumes increased 1% from Q4/10 and 10% from Q3/11 as a result of increased production from Horizon, the impact of record primary heavy crude oil and light crude oil drilling programs offset by the timing of steaming cycles in Bitumen ("thermal in situ").
- Total natural gas production for Q4/11 was 1,280 MMcf/d. Q4/11 natural gas production volumes increased 2% over Q4/10 and Q3/11. The increase in production reflects the impact of natural gas producing properties acquired during 2011 and strong performance from the Company's natural gas drilling program.

- Canadian Natural generated record quarterly cash flow from operations of $2.16 billion representing an increase of 31% from Q4/10 and an increase of 22% from Q3/11. The increase in cash flow from Q4/10 was primarily related to higher North America crude oil and NGL sales volumes and higher crude oil and NGL netbacks. The increase in cash flow from Q3/11 was primarily a result of increased production from Horizon.

- Adjusted net earnings from operations for Q4/11 was $972 million, compared to adjusted net earnings of $585 million in Q4/10 and $719 million in Q3/11. Changes in adjusted net earnings reflect the changes in cash flow from operations.

- The Company has finalized its Horizon coker fire business interruption insurance claim for $333 million and its property damage insurance claim for $393 million for a total of $726 million. To date, the Company has received total combined insurance proceeds of approximately $400 million, and expects to receive the remaining balance by the end of Q1/12.

Annual

- Total crude oil and NGLs production for the year averaged 389,053 bbl/d representing a decrease of 8% from 2010. Increased production from primary heavy crude oil, thermal in situ and light crude oil and NGL was more than offset by reduced production from Horizon and the Company's international operations.

- Total natural gas production for the year averaged 1,257 MMcf/d representing an increase of 1% from 2010. The increase in production was a result of natural gas producing properties acquired in 2010 and 2011 and strong results from a modest, liquids rich drilling program offset by expected production declines. The acquired properties provide opportunities to lower operating costs and capture synergies with existing infrastructure. Canadian Natural drilled 86 net natural gas wells in 2011, a reduction of 12% from 2010 reflecting the Company's strategic decision to allocate capital to higher return crude oil projects.

- Cash flow from operations was approximately $6.5 billion in 2011 compared to approximately $6.3 billion in 2010. The increase in cash flow was primarily a result of higher crude oil and NGL netbacks and higher North America exploration and production crude oil and NGL sales volumes offset by reduced production from Horizon.

- Adjusted net earnings from operations in 2011 increased to $2.5 billion compared to $2.4 billion in 2010. Changes in adjusted net earnings reflect the changes in cash flow from operations.

- Canadian Natural's crude oil and natural gas reserves were reviewed and evaluated by independent qualified reserves evaluators. The following are highlights based on the Company's gross reserves using forecast prices and costs as at December 31, 2011:
  - Company Gross proved crude oil, SCO, bitumen and NGL reserves increased 8% to 4.09 billion barrels. Company Gross proved natural gas reserves increased 4% to 4.45 Tcf. Total proved reserves increased 7% to 4.83 billion BOE.
  - Company Gross proved plus probable crude oil, SCO, bitumen and NGL reserves increased 10% to 6.52 billion barrels. Company Gross proved plus probable natural gas reserves increased 6% to 6.10 Tcf. Total proved plus probable reserves increased 9% to 7.54 billion BOE.
  - Company Gross proved reserve additions, including acquisitions, were 437 million barrels of crude oil, SCO, bitumen and NGL and 644 billion cubic feet of natural gas for 545 million BOE. The total proved reserve replacement ratio was 249%. The total proved reserve life index is 21.4 years.
  - Company Gross proved plus probable reserve additions, including acquisitions, were 722 million barrels of crude oil, bitumen, SCO and NGL and 793 billion cubic feet of natural gas for 855 million BOE. The total proved plus probable reserve replacement ratio was 390%. The total proved plus probable reserve life index is 33.3 years.
  - Proved undeveloped crude oil, SCO, bitumen and NGL reserves accounted for 29% of the corporate total proved reserves and proved undeveloped natural gas reserves accounted for 4% of the corporate total proved reserves.

- Total net exploration and production reserve replacement expenditures totaled approximately $5.0 billion in 2011, including acquisitions and excluding Horizon. Horizon project capital (including capitalized interest, share-based compensation and other) totaled approximately $530 million and sustaining and turnaround capital totaled approximately $250 million.

Operational and Financial

- Primary heavy crude oil operations achieved record quarterly production in Q4/11 of approximately 111,500 bbl/d which contributed to 11% average annual production growth over 2010. Canadian Natural executed a record drilling program, drilling 783 net primary heavy crude oil wells in 2011. The Company exited December 2011 with production over 115,000 bbl/d representing an increase of approximately 19% compared to the first quarter of 2011.

- Thermal in situ production achieved 9% growth in 2011 over 2010 through the optimization of steaming techniques and the development of low cost pads at Primrose, Canadian Natural's cyclic steam stimulation project. The Company targets to increase production by another 9% in 2012.

- Construction at the Kirby South Phase 1 project remains on cost and on schedule with first steam in targeted for late 2013. During Q4/11 drilling has been completed on the second of seven pads and has commenced on the third pad with wells confirming geological expectations.

- The application for regulatory approval for Kirby North Phase 1 was submitted in Q4/11 and the application for Grouse was submitted in Q1/12.

- At Pelican Lake, results of the world class polymer flood continue to be positive. As expected the polymer flood delivered a 15% increase in Company Gross crude oil proved reserves over 2010 as a result of optimized well configurations and injection strategies.

- SCO production at the Horizon Oil Sands averaged approximately 103,000 bbl/d in Q4/11, an 11% increase over Q4/10. Production averaged approximately 81,000 bbl/d in January 2012. On February 5, 2012 production was fully suspended for unplanned maintenance on the Fractionating Unit, with full production of SCO targeted to resume in mid to late March. Cost estimates for the repairs are expected to be approximately $35 million.

- Commissioning of the third Ore Preparation Plant ("OPP") and associated hydro-transport unit began in late Q4/11. In January 2012 the third OPP and associated hydro-transport unit were turned over to operations for startup. The third OPP will increase production reliability and result in higher plant uptime going forward at Horizon.

- 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 40% of its forecasted 2012 crude oil volumes through a combination of puts and collars.

- Canadian Natural has increased its cash dividend on common shares for the twelfth year in a row. In 2012, the quarterly dividend on common shares will increase by approximately 17% from $0.09 to $0.105 per common share, payable April 1, 2012. The dividend increase represents a 21% Compound Annual Growth Rate ("CAGR") since the Company first paid a dividend in 2001.

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, thermal in situ (Bitumen), 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

Activity by core region

	Net unproved properties as at Dec 31, 2011 (thousands of net acres)[1]	Drilling activity year ended Dec 31, 2011 (net wells)[2]
North America		
Northeast British Columbia	**3,051**	**28.3**
Northwest Alberta	**1,986**	**88.0**
Northern Plains	**6,581**	**915.7**
Southern Plains	**989**	**44.8**
Southeast Saskatchewan	**102**	**40.3**
Bitumen (“Thermal In Situ”) Oil Sands	**817**	**485.6**
	13,526	**1,602.7**
Oil Sands Mining and Upgrading	**59**	**286.0**
North Sea	**128**	**0.9**
Offshore Africa	**4,191**	**0.9**
	17,904	**1,890.5**

(1) Unproved land refers to a property or part of a property to which no reserves have been specifically attributed.

(2) Drilling activity includes stratigraphic test and service wells.

Drilling activity (number of wells)

	Year Ended Dec 31			
	2011		2010	
	Gross	**Net**	Gross	Net
Crude oil	**1,159**	**1,103**	997	934
Natural gas	**102**	**83**	112	92
Dry	**49**	**48**	38	33
Subtotal	**1,310**	**1,234**	1,147	1,059
Stratigraphic test / service wells	**659**	**657**	492	491
Total	**1,969**	**1,891**	1,639	1,550
Success rate (excluding stratigraphic test / service wells)		**96%**		97%

North America Exploration and Production

North America natural gas

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Natural gas production (MMcf/d)	**1,255**	1,226	1,223	**1,231**	1,217
Net wells targeting natural gas	**29**	21	19	**86**	98
Net successful wells drilled	**27**	21	18	**83**	92
Success rate	**93%**	100%	95%	**97%**	94%

- North America natural gas production for the year averaged 1,231 MMcf/d representing an increase of 1% from 2010. The increase in production was a result of natural gas producing properties acquired in 2010 and 2011 and strong results from a modest, liquids rich drilling program offset by natural declines. The acquired properties provided opportunities to lower operating costs and capture synergies with existing infrastructure. Canadian Natural drilled 86 net natural gas wells in 2011, a reduction of 12% from 2010 reflecting the Company's strategic decision to allocate capital to higher return crude oil projects.

- North America natural gas production for Q4/11 was 1,255 MMcf/d. Q4/11 natural gas production volumes increased 3% from Q4/10 and 2% from Q3/11. The increase in production reflects the impact of natural gas producing properties acquired during 2011 and strong performance from the Company's natural gas drilling program.

- Septimus continues to exceed expectations. In 2011, Canadian Natural drilled 13 net wells and completed a tie-in to a deep cut gas facility to increase liquid recoveries. In 2012, the Company plans to expand the plant at Septimus to 120 MMcf/d yielding approximately 10,000 bbl/d of liquids and targets to drill 17 net wells to maximize facility utilization.

- Reflecting Canadian Natural's responsible and flexible allocation of capital, the Company has reduced its natural gas capital expenditures for 2012 by $170 million. This reduction in capital spending will reduce natural gas production by approximately 20 MMcf/d and 460 bbl/d of liquids in 2012.

North America crude oil and NGLs

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Crude oil and NGLs production (bbl/d)	**291,839**	304,671	286,698	**295,618**	270,562
Net wells targeting crude oil	**345**	327	323	**1,147**	953
Net successful wells drilled	**330**	317	316	**1,103**	926
Success rate	**96%**	97%	98%	**96%**	97%

- North America crude oil and NGLs production for the year averaged 295,618 bbl/d representing an increase of 9% from 2010. The increase in production was a result of record drilling programs in primary heavy and light crude oil, optimized steam techniques and the development of new low cost pads at Primrose.
- North America crude oil and NGLs production for Q4/11 was 291,839 bbl/d. Q4/11 crude oil and NGLs production volumes increased 2% from Q4/10 and decreased 4% from Q3/11. The decrease in production from Q3/11 was primarily due to the timing of steaming cycles in thermal in situ partially offset by record quarterly production in primary heavy crude oil.
- Primary heavy crude oil operations achieved record quarterly production in Q4/11 of approximately 111,500 bbl/d which contributed to 11% average annual production growth over 2010. Canadian Natural executed a record drilling program, drilling 783 net primary heavy crude oil wells in 2011. The Company exited December 2011 with production over 115,000 bbl/d representing an increase of approximately 19% compared to the first quarter of 2011. Primary heavy crude oil continues to provide one of the highest return on capital projects in the Company's portfolio and excellent short term growth to complement longer term projects.
- Thermal in situ production achieved 9% growth in 2011 over 2010 through the optimization of steaming techniques and the development of low cost pads at Primrose, Canadian Natural's cyclic steam stimulation project. The Company targets to increase production by another 9% in 2012.
- 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 the performance of future projects. 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.
    - Construction at the Kirby South Phase 1 project remains on cost and on schedule with first steam in targeted for late 2013. Drilling has been completed on the second of seven pads and has commenced on the third pad with wells confirming geological expectations.
    - The application for regulatory approval for Kirby North Phase 1 was submitted in Q4/11 and the application for Grouse was submitted in Q1/12.
    - Canadian Natural has an active stratigraphic ("strat") test well drilling program to delineate the reservoir characteristics for future projects. The Company targets to drill over 400 strat wells in 2012.
- At Pelican Lake, results of the world class polymer flood continue to be positive. As expected the polymer flood delivered a 15% increase in gross crude oil proved reserves over 2010 as a result of optimized well configurations and injection strategies.
- North America light crude oil production increased 10% in 2011 over 2010 on the back of a record drilling program. In 2012, Canadian Natural targets to drill 134 net light crude oil wells including nine new pool developments.
- Planned drilling activity for 2012 includes 159 net thermal in situ wells and 956 net crude oil wells, excluding strat test and service wells.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Crude oil production (bbl/d)					
North Sea	**26,769**	26,350	31,701	**29,992**	33,292
Offshore Africa	**22,726**	22,525	27,706	**23,009**	30,264
Natural gas production (MMcf/d)					
North Sea	**6**	5	9	**7**	10
Offshore Africa	**19**	21	20	**19**	16
Net wells targeting crude oil	**0.0**	0.0	2.4	**0.9**	8.0
Net successful wells drilled	**0.0**	0.0	2.4	**0.0**	8.0
Success rate	**0%**	0%	100%	**0%**	100%

- North Sea crude oil production averaged 26,769 bbl/d during Q4/11 representing a decrease of 16% compared to Q4/10 and an increase of 2% compared to Q3/11. The decrease from Q4/10 was a result of scheduled turnarounds and natural field declines.
- On December 8, 2011, the Banff floating production, storage and offloading vessel ("FPSO") and subsea infrastructure suffered damage from severe storm conditions. The FPSO has been removed from the field and the extent of the damage including associated costs is being assessed. The resulting effect on 2012 production is approximately 3,500 bbl/d and is reflected in the Company's updated guidance. The incident is an insurable event for both property damage and profit-based business interruption insurance.
- In 2011 the UK government implemented a tax increase in the North Sea that resulted in a 24% reduction in the UK North Sea after-tax profits. As a result the Company has curtailed much of the long term volume adding investment in the North Sea. The Company will continue to high grade all North Sea prospects for potential future development opportunities.
- Production in Offshore Africa averaged 22,726 bbl/d during Q4/11 representing a decrease of 18% compared to Q4/10 and an increase of 1% compared to Q3/11. The decrease from Q4/10 was a result of natural field declines and lower production entitlements following the payout of the Baobab Field in May 2011. Infill drilling at the Espoir Field is targeted to begin in late 2012, targeting additional production of 6,500 BOE per day at the completion of this drilling program.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Synthetic crude oil production (bbl/d)	**102,952**	50,354	92,730	**40,434**	90,867

- SCO production at the Horizon Oil Sands averaged approximately 103,000 bbl/d in Q4/11, an 11% increase over Q4/10. Production averaged approximately 81,000 bbl/d in January 2012. On February 5, 2012 production was fully suspended for unplanned maintenance on the Fractionating Unit, with full production of SCO targeted to resume in mid to late March. Cost estimates for the repairs are expected to be approximately $35 million.
- Commissioning of the third OPP and associated hydro-transport unit began in late Q4/11. In January 2012 the third OPP and associated hydro-transport unit were turned over to operations for startup. The third OPP will increase production reliability and result in higher plant uptime going forward at Horizon.
- Horizon expansion activities continue to progress on track and are at or below cost estimates. Lump sum contracts for the Gasoil Hydrotreater, Froth Treatment and Hydrogen Plant have been awarded and will enhance cost certainty going forward.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 94.02**	$ 89.81	$ 85.18	**$ 95.14**	$ 79.55
Western Canadian Select blend differential from WTI (%)	**11%**	20%	21%	**18%**	18%
SCO price (US$/bbl) (2)	**$ 102.95**	$ 100.64	$ 83.14	**$ 103.63**	$ 78.56
Average realized pricing before risk management (C$/bbl) (3)	**$ 85.28**	$ 73.80	$ 67.74	**$ 77.46**	$ 65.81
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 3.29**	$ 3.53	$ 3.39	**$ 3.48**	$ 3.91
Average realized pricing before risk management (C$/Mcf)	**$ 3.50**	$ 3.76	$ 3.56	**$ 3.73**	$ 4.08

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

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

(3) Excludes SCO.

- In Q4/11, WTI pricing increased by 5% from Q3/11 partially due to the announcement of the Seaway pipeline reversal from Cushing, Oklahoma to the US Gulf Coast where a large concentration of heavy crude oil refineries exist, offset by the relative strengthening of the US dollar.

- The Western Canadian Select ("WCS") heavy crude oil differential as a percent of WTI averaged 11% in Q4/11. The WCS heavy differential narrowed in Q4/11 from Q3/11 as a result of increased heavy crude oil conversion capacity from key refineries in Petroleum Administration for Defence Districts II ("PADD II").

- In 2011, the Company contributed approximately 162,000 bbl/d of its heavy crude oil streams to the WCS blend. Canadian Natural is the largest contributor accounting for 55% of the WCS blend.

REDWATER UPGRADING AND REFINING

- In Q1/11, Canadian Natural announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen refinery near Redwater, Alberta. In addition, the partnership had entered into a 30 year fee-for-service agreement to process bitumen supplied by 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 for 2012.

FINANCIAL REVIEW

- The financial position of Canadian Natural remains strong as the Company continues to focus on capital allocation and the execution of implemented strategies. Canadian Natural's 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 598,526 BOE/d in 2011 and over 96% of production was located in G8 countries.

    - A strong balance sheet with debt to book capitalization of 27% and debt to EBITDA of 1.1 times. At December 31, 2011 long-term debt amounted to $8.6 billion compared with $8.5 billion at December 31, 2010.

- Canadian Natural maintained significant financial stability and increased liquidity in 2011, exiting the year with approximately $3.8 billion in available unused bank lines. In Q4/11, the Company issued US$1 billion of debt securities comprised of 3 and 10 year unsecured notes at 1.45% and 3.45% respectively. Proceeds from these securities were used to repay bank indebtedness. The 10 year unsecured notes were subsequently swapped to a Canadian obligation at 3.96%.

- Standard and Poor's Financial Services LLC upgraded the Company's unsecured credit rating to BBB+ (Stable outlook) from BBB (Positive outlook) in 2011.

- 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 40% of its forecasted 2012 crude oil volumes through a combination of puts and collars.

- In 2011, the Canadian Natural acquired 3.071 million common shares at an average cost of $33.68/share under the Company's Normal Course Issuer Bid.

- Canadian Natural has increased its cash dividend on common shares for the twelfth year in a row. In 2012, the quarterly dividend on common shares will increase by approximately 17% from $0.09 to $0.105 per common share, payable April 1, 2012. The dividend increase represents a 21% CAGR since the Company first paid a dividend in 2001.

OUTLOOK

The Company forecasts 2012 production levels before royalties to average between 1,247 and 1,297 MMcf/d of natural gas and between 440,000 and 480,000 bbl/d of crude oil and NGLs. Q1/12 production guidance before royalties is forecast to average between 1,300 and 1,320 MMcf/d of natural gas and between 367,000 and 400,000 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.

YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2011 the Company retained Independent Qualified Reserves Evaluators ("Evaluators"), Sproule Associates Limited ("Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves. Sproule evaluated the Company's North America and International crude oil, bitumen, natural gas and NGL reserves. GLJ evaluated the Company's Horizon synthetic crude oil reserves. The Evaluators conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the Evaluators as to the Company's reserves.

Corporate Total

- Company Gross proved crude oil, SCO, bitumen and NGL reserves increased 8% to 4.09 billion barrels. Company Gross proved natural gas reserves increased 4% to 4.45 Tcf. Total proved reserves increased 7% to 4.83 billion BOE.
- Company Gross proved plus probable crude oil, SCO, bitumen and NGL reserves increased 10% to 6.52 billion barrels. Company Gross proved plus probable natural gas reserves increased 6% to 6.10 Tcf. Total proved plus probable reserves increased 9% to 7.54 billion BOE.
- Company Gross proved reserve additions, including acquisitions, were 437 million barrels of crude oil, SCO, bitumen and NGL and 644 billion cubic feet of natural gas for 545 million BOE. The total proved reserve replacement ratio was 249%. The total proved reserve life index is 21.4 years.
- Company Gross proved plus probable reserve additions, including acquisitions, were 722 million barrels of crude oil, bitumen, SCO and NGL and 793 billion cubic feet of natural gas for 855 million BOE. The total proved plus probable reserve replacement ratio was 390%. The total proved plus probable reserve life index is 33.3 years.
- Proved undeveloped crude oil, SCO, bitumen and NGL reserves accounted for 29% of the corporate total proved reserves and proved undeveloped natural gas reserves accounted for 4% of the corporate total proved reserves.

North America Exploration and Production

- North America Company Gross proved crude oil, bitumen and NGL reserves increased 10% to 1.63 billion barrels. Company Gross proved natural gas reserves increased 4% to 4.27 Tcf. Total proved BOE increased 8% to 2.35 billion barrels.
- North America Company Gross proved plus probable crude oil, bitumen and NGL reserves increased 6% to 2.65 billion barrels. Company Gross proved plus probable natural gas reserves increased 6% to 5.84 Tcf. Total proved plus probable BOE increased 6% to 3.63 billion barrels.
- North America Company Gross proved reserve additions, including acquisitions, were 251 million barrels of crude oil, bitumen and NGL and 623 billion cubic feet of natural gas for 355 million BOE. The total proved reserve replacement ratio is 194%. The total proved reserve life index in 13.9 years.
- Proved undeveloped crude oil, bitumen and NGL reserves accounted for 39% of the North America total proved reserves and proved undeveloped natural gas reserves accounted for 8% of the North America total proved reserves.
- Pelican Lake heavy crude oil Company Gross proved reserves increased 15% to 276 million barrels due to continued expansion and improved performance from the polymer flood project. Proved reserve additions were 51 million barrels.
- Thermal oil Company Gross proved reserves increased 6% to 974 million barrels primarily due to category transfers from probable undeveloped to proved undeveloped at Kirby North and new proved undeveloped additions at Primrose. Proved reserve additions were 91 million barrels.

North America Oil Sands Mining and Upgrading

- Company Gross proved synthetic crude oil reserves increased 10% to 2.12 billion barrels and proved plus probable reserves increased 16% to 3.36 billion barrels.
- Proved reserve additions were 202 million barrels primarily due to additional stratigraphic wells drilled in the north pit. Probable reserve additions were 280 million barrels from expansion of the north pit.

International Exploration and Production

- North Sea Company Gross proved reserves decreased 8% to 244 million barrels of oil equivalent due to cancellation of the Company's activity in response to the changes in the UK fiscal structure. North Sea Company Gross proved plus probable reserves are 371 million barrels of oil equivalent.
- Offshore Africa Company Gross proved reserves decreased 9% to 123 million barrels of oil equivalent due to production and technical revisions. Offshore Africa Company Gross proved plus probable reserves are 187 million barrels of oil equivalent.

Summary of Company Gross Crude Oil, Bitumen, Natural Gas & NGL Reserves
As of December 31, 2011
Forecast Prices and Costs

	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
North America								
Proved								
Developed Producing	94	76	204	193	1,831	2,975	56	2,950
Developed Non-Producing	3	20	1	71	-	170	2	125
Undeveloped	17	79	71	710	288	1,121	37	1,389
Total Proved	114	175	276	974	2,119	4,266	95	4,464
Probable	41	74	112	752	1,236	1,572	39	2,516
Total Proved plus Probable	155	249	388	1,726	3,355	5,838	134	6,980
North Sea								
Proved								
Developed Producing	59					7		60
Developed Non-Producing	13					56		22
Undeveloped	156					35		162
Total Proved	228					98		244
Probable	121					36		127
Total Proved plus Probable	349					134		371
Offshore Africa								
Proved								
Developed Producing	73					74		85
Developed Non-Producing	-					-		-
Undeveloped	36					9		38
Total Proved	109					83		123
Probable	56					46		64
Total Proved plus Probable	165					129		187
Total Company								
Proved								
Developed Producing	226	76	204	193	1,831	3,056	56	3,095
Developed Non-Producing	16	20	1	71	-	226	2	147
Undeveloped	209	79	71	710	288	1,165	37	1,589
Total Proved	451	175	276	974	2,119	4,447	95	4,831
Probable	218	74	112	752	1,236	1,654	39	2,707
Total Proved plus Probable	669	249	388	1,726	3,355	6,101	134	7,538

Summary of Company Net Crude Oil, Bitumen, Natural Gas & NGL Reserves
As of December 31, 2011
Forecast Prices and Costs

	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
North America								
Proved								
Developed Producing	79	63	155	143	1,514	2,663	39	2,437
Developed Non-Producing	3	17	1	51	-	141	2	98
Undeveloped	14	68	54	539	236	974	29	1,102
Total Proved	96	148	210	733	1,750	3,778	70	3,637
Probable	34	59	78	575	995	1,347	29	1,994
Total Proved plus Probable	130	207	288	1,308	2,745	5,125	99	5,631
North Sea								
Proved								
Developed Producing	59					7		60
Developed Non-Producing	13					56		22
Undeveloped	156					35		162
Total Proved	228					98		244
Probable	121					36		127
Total Proved plus Probable	349					134		371
Offshore Africa								
Proved								
Developed Producing	60					47		68
Developed Non-Producing	-					-		-
Undeveloped	27					7		28
Total Proved	87					54		96
Probable	44					29		49
Total Proved plus Probable	131					83		145
Total Company								
Proved								
Developed Producing	198	63	155	143	1,514	2,717	39	2,565
Developed Non-Producing	16	17	1	51	-	197	2	120
Undeveloped	197	68	54	539	236	1,016	29	1,292
Total Proved	411	148	210	733	1,750	3,930	70	3,977
Probable	199	59	78	575	995	1,412	29	2,170
Total Proved plus Probable	610	207	288	1,308	2,745	5,342	99	6,147

Reconciliation of Company Gross Reserves by Product
As of December 31, 2011
Forecast Prices and Costs

PROVED

North America	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2010	110	160	239	919	1,932	4,092	63	4,105
Discoveries	-	1	-	-	-	7	-	2
Extensions	7	47	8	20	-	220	18	137
Infill Drilling	6	8	-	2	-	55	3	28
Improved Recovery	-	1	-	-	-	-	-	1
Acquisitions	2	-	-	-	-	432	7	81
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	4	(177)	(1)	(26)
Technical Revisions	2	(4)	43	69	198	86	12	334
Production	(13)	(38)	(14)	(36)	(15)	(449)	(7)	(198)
December 31, 2011	114	175	276	974	2,119	4,266	95	4,464

North Sea

	Light and Medium Oil MMbbl	Natural Gas Bcf	Barrels of Oil Equivalent MMBOE
December 31, 2010	252	78	265
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	28	3	29
Technical Revisions	(41)	20	(38)
Production	(11)	(3)	(12)
December 31, 2011	228	98	244

Offshore Africa

	Light and Medium Oil MMbbl	Natural Gas Bcf	Barrels of Oil Equivalent MMBOE
December 31, 2010	120	92	135
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	2	-	2
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	(5)	(2)	(5)
Production	(8)	(7)	(9)
December 31, 2011	109	83	123

Total Company

	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2010	482	160	239	919	1,932	4,262	63	4,505
Discoveries	-	1	-	-	-	7	-	2
Extensions	7	47	8	20	-	220	18	137
Infill Drilling	8	8	-	2	-	55	3	30
Improved Recovery	-	1	-	-	-	-	-	1
Acquisitions	2	-	-	-	-	432	7	81
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	28	-	-	-	4	(174)	(1)	3
Technical Revisions	(44)	(4)	43	69	198	104	12	291
Production	(32)	(38)	(14)	(36)	(15)	(459)	(7)	(219)
December 31, 2011	451	175	276	974	2,119	4,447	95	4,831

Reconciliation of Company Gross Reserves by Product
As of December 31, 2011
Forecast Prices and Costs

PROBABLE

North America	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2010	40	57	109	783	956	1,430	20	2,203
Discoveries	-	-	-	-	-	1	-	-
Extensions	3	22	6	17	388	122	11	468
Infill Drilling	3	4	-	1	-	54	4	21
Improved Recovery	1	3	-	-	-	-	-	4
Acquisitions	-	-	-	-	-	104	2	19
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	-	(34)	(1)	(7)
Technical Revisions	(6)	(12)	(3)	(49)	(108)	(104)	3	(192)
Production	-	-	-	-	-	-	-	-
December 31, 2011	41	74	112	752	1,236	1,572	39	2,516

North Sea	Light and Medium Oil MMbbl	Natural Gas Bcf	Barrels of Oil Equivalent MMBOE
December 31, 2010	124	29	129
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	(26)	-	(26)
Technical Revisions	23	7	24
Production	-	-	-
December 31, 2011	121	36	127

Offshore Africa	Light and Medium Oil MMbbl	Natural Gas Bcf	Barrels of Oil Equivalent MMBOE
December 31, 2010	57	46	65
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	(1)	-	(1)
Production	-	-	-
December 31, 2011	56	46	64

Total Company	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2010	221	57	109	783	956	1,505	20	2,397
Discoveries	-	-	-	-	-	1	-	-
Extensions	3	22	6	17	388	122	11	468
Infill Drilling	3	4	-	1	-	54	4	21
Improved Recovery	1	3	-	-	-	-	-	4
Acquisitions	-	-	-	-	-	104	2	19
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	(26)	-	-	-	-	(34)	(1)	(33)
Technical Revisions	16	(12)	(3)	(49)	(108)	(97)	3	(169)
Production	-	-	-	-	-	-	-	-
December 31, 2011	218	74	112	752	1,236	1,654	39	2,707

Reconciliation of Company Gross Reserves by Product
As of December 31, 2011
Forecast Prices and Costs

PROVED PLUS PROBABLE

North America	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2010	150	217	348	1,702	2,888	5,522	83	6,308
Discoveries	-	1	-	-	-	8	-	2
Extensions	10	69	14	37	388	342	29	605
Infill Drilling	9	12	-	3	-	109	7	49
Improved Recovery	1	4	-	-	-	-	-	5
Acquisitions	2	-	-	-	-	536	9	100
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	4	(211)	(2)	(33)
Technical Revisions	(4)	(16)	40	20	90	(18)	15	142
Production	(13)	(38)	(14)	(36)	(15)	(449)	(7)	(198)
December 31, 2011	155	249	388	1,726	3,355	5,838	134	6,980

North Sea

	Light and Medium Oil MMbbl	Natural Gas Bcf	Barrels of Oil Equivalent MMBOE
December 31, 2010	376	107	394
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	2	3	3
Technical Revisions	(18)	27	(14)
Production	(11)	(3)	(12)
December 31, 2011	349	134	371

Offshore Africa

	Light and Medium Oil MMbbl	Natural Gas Bcf	Barrels of Oil Equivalent MMBOE
December 31, 2010	177	138	200
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	2	-	2
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	(6)	(2)	(6)
Production	(8)	(7)	(9)
December 31, 2011	165	129	187

Total Company

	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2010	703	217	348	1,702	2,888	5,767	83	6,902
Discoveries	-	1	-	-	-	8	-	2
Extensions	10	69	14	37	388	342	29	605
Infill Drilling	11	12	-	3	-	109	7	51
Improved Recovery	1	4	-	-	-	-	-	5
Acquisitions	2	-	-	-	-	536	9	100
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	2	-	-	-	4	(208)	(2)	(30)
Technical Revisions	(28)	(16)	40	20	90	7	15	122
Production	(32)	(38)	(14)	(36)	(15)	(459)	(7)	(219)
December 31, 2011	669	249	388	1,726	3,355	6,101	134	7,538

(1) Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.

(2) Company Net reserves are working interest share after deduction of royalties and including any royalty interests.

(3) Forecast pricing assumptions utilized by the independent qualified reserves evaluators in the reserve estimates were provided by Sproule Associates Limited:

	2012	2013	2014	2015	2016	Average annual increase thereafter
Crude oil and NGLs						
WTI at Cushing (US$/bbl)	$ 98.07	$ 94.90	$ 92.00	$ 97.42	$ 99.37	2%
Western Canada Select (C$/bbl)	$ 82.34	$ 79.69	$ 77.25	$ 81.80	$ 83.44	2%
Edmonton Par (C$/bbl)	$ 96.87	$ 93.75	$ 90.89	$ 96.23	$ 98.16	2%
Edmonton Pentanes+ (C$/bbl)	$ 103.57	$ 100.23	$ 97.17	$ 102.89	$ 104.94	2%
North Sea Brent (US$/bbl)	$ 106.65	$ 102.15	$ 97.70	$ 103.26	$ 105.32	2%
Natural gas						
AECO (C$/MMBtu)	$ 3.16	$ 3.78	$ 4.13	$ 5.53	$ 5.65	2%
BC Westcoast Station 2 (C$/MMBtu)	$ 3.10	$ 3.72	$ 4.07	$ 5.47	$ 5.59	2%
Henry Hub Louisiana (US$/MMBtu)	$ 3.55	$ 4.18	$ 4.54	$ 5.95	$ 6.07	2%

A foreign exchange rate of US$1.012/C$1.000 was used in the 2011 evaluation.

(4) Reserve additions are comprised of all categories of Company Gross reserve changes, exclusive of production.

(5) Reserve replacement ratio is the Company Gross reserve additions divided by the Company Gross production in the same period.

(6) 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.

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, recommencement of production at Horizon, ability to recover insurance proceeds, Primrose, Pelican Lake, Olowi field (Offshore Gabon), 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 and year ended December 31, 2011 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2010.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. Common share data and per common share amounts have been restated to reflect the two-for-one common share split in May 2010. The Company’s consolidated financial statements for the period ended December 31, 2011 and this MD&A have been prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board (“IASB”). Unless otherwise stated, 2010 comparative figures have been restated in accordance with IFRS issued as at December 31, 2011. Comparative figures for 2009 have not been restated from Canadian GAAP as previously reported and may not be prepared on a basis consistent with IFRS as adopted. 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 and year ended December 31, 2011 in relation to the comparable periods in 2010 and the third quarter of 2011. The accompanying tables form an integral part of this MD&A. This MD&A is dated March 6, 2012. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2010, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Product sales	**$ 4,788**	$ 3,690	$ 3,787	**$ 15,507**	$ 14,322
Net earnings (loss)	**$ 832**	$ 836	$ (309)	**$ 2,643**	$ 1,673
Per common share – basic	**$ 0.76**	$ 0.76	$ (0.28)	**$ 2.41**	$ 1.54
– diluted	**$ 0.76**	$ 0.76	$ (0.28)	**$ 2.40**	$ 1.53
Adjusted net earnings from operations (1)	**$ 972**	$ 719	$ 585	**$ 2,540**	$ 2,444
Per common share – basic	**$ 0.89**	$ 0.65	$ 0.54	**$ 2.32**	$ 2.25
– diluted	**$ 0.88**	$ 0.65	$ 0.53	**$ 2.30**	$ 2.23
Cash flow from operations (2)	**$ 2,158**	$ 1,767	$ 1,652	**$ 6,547**	$ 6,333
Per common share – basic	**$ 1.97**	$ 1.62	$ 1.52	**$ 5.98**	$ 5.82
– diluted	**$ 1.96**	$ 1.60	$ 1.50	**$ 5.94**	$ 5.78
Capital expenditures, net of dispositions	**$ 1,909**	$ 1,406	$ 1,945	**$ 6,414**	$ 5,514

(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 below lists certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

($ millions)	*Three Months Ended*			*Year Ended*	
	Dec 31 2011	*Sep 30 2011*	*Dec 31 2010*	***Dec 31 2011***	*Dec 31 2010*
Net earnings (loss) as reported	***$ 832***	*$ 836*	*$ (309)*	***$ 2,643***	*$ 1,673*
Share-based compensation expense (recovery), net of tax (a) (e)	***207***	*(249)*	*266*	***(102)***	*203*
Unrealized risk management loss (gain), net of tax (b)	***50***	*(97)*	*136*	***(95)***	*(16)*
Unrealized foreign exchange (gain) loss, net of tax (c)	***(117)***	*454*	*(102)*	***215***	*(142)*
Gabon, Offshore Africa asset impairment	***–***	*–*	*594*	***–***	*594*
Realized foreign exchange gain on repayment of US dollar debt securities, net of tax (d)	***–***	*(225)*	*–*	***(225)***	*–*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (e)	***–***	*–*	*–*	***104***	*132*
Adjusted net earnings from operations	***$ 972***	*$ 719*	*$ 585*	***$ 2,540***	*$ 2,444*

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

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

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

(d) During the third quarter of 2011, the Company repaid US$400 million of US dollar debt securities bearing interest at 6.70%.

(e) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. 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. During 2010, changes in Canada to the taxation of stock options surrendered by employees for cash payments resulted in a $132 million charge to deferred income tax expense.

Cash Flow from Operations

($ millions)	Three Months Ended **Dec 31 2011**	Sep 30 2011	Dec 31 2010	Year Ended **Dec 31 2011**	Dec 31 2010
Net earnings (loss)	***$ 832***	*$ 836*	*$ (309)*	***$ 2,643***	*$ 1,673*
Non-cash items:					
Depletion, depreciation and amortization	***998***	*887*	*1,546*	***3,604***	*4,120*
Share-based compensation expense (recovery)	***207***	*(249)*	*266*	***(102)***	*203*
Asset retirement obligation accretion	***33***	*33*	*31*	***130***	*123*
Unrealized risk management loss (gain)	***58***	*(122)*	*180*	***(128)***	*(24)*
Unrealized foreign exchange (gain) loss	***(117)***	*454*	*(116)*	***215***	*(161)*
Realized foreign exchange gain on repayment of US dollar debt securities	***–***	*(225)*	*–*	***(225)***	*–*
Deferred income tax expense	***144***	*153*	*54*	***407***	*399*
Horizon asset impairment provision	***–***	*–*	*–*	***396***	*–*
Insurance recovery – property damage	***3***	*–*	*–*	***(393)***	*–*
Cash flow from operations	***$ 2,158***	*$ 1,767*	*$ 1,652*	***$ 6,547***	*$ 6,333*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the year ended December 31, 2011 were $2,643 million compared to $1,673 million for the year ended December 31, 2010. Net earnings for the year ended December 31, 2011 included net after-tax income of $103 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of realized foreign exchange gain on repayment of long-term debt and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities, compared to net after-tax expenses of $771 million for the year ended December 31, 2010. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2011 were $2,540 million, compared to $2,444 million for the year ended December 31, 2010.

Net earnings for the fourth quarter of 2011 were $832 million compared to a net loss of $309 million for the fourth quarter of 2010 and net earnings of $836 million for the third quarter of 2011. Net earnings for the fourth quarter of 2011 included net after-tax expenses of $140 million related to the effects of share-based compensation, risk management activities, and fluctuations in foreign exchange rates, compared to net after-tax expenses of $894 million for the fourth quarter of 2010 and net after-tax income of $117 million for the third quarter of 2011. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2011 were $972 million compared to $585 million for the fourth quarter of 2010 and $719 million for the third quarter of 2011.

The increase in adjusted net earnings for the year ended December 31, 2011 from the year ended December 31, 2010 was primarily due to:

- higher North America crude oil and NGL sales volumes;
- higher crude oil and NGL netbacks;
- lower net interest and other financing costs;

partially offset by:

- the impact of suspension of production at Horizon, net of business interruption insurance;
- lower natural gas netbacks;
- realized risk management losses; and
- the impact of a stronger Canadian dollar.

The increase in adjusted net earnings for the fourth quarter of 2011 from the fourth quarter of 2010 was primarily due to:

- higher North America and Horizon crude oil and NGL sales volumes;
- higher crude oil and NGL netbacks;
- lower net interest and other financing costs; and
- the impact of a weaker Canadian dollar.

partially offset by lower natural gas netbacks.

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

- higher Horizon crude oil and NGL sales volumes;
- higher crude oil and NGL netbacks; and
- the impact of a weaker Canadian dollar;

partially offset by:

- lower North America crude oil and NGL sales volumes;
- lower natural gas netbacks;
- higher depletion, depreciation and amortization expense; and
- realized risk management losses.

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

Cash flow from operations for the year ended December 31, 2011 was $6,547 million compared to $6,333 million for the year ended December 31, 2010. Cash flow from operations for the fourth quarter of 2011 was $2,158 million compared to $1,652 million for the fourth quarter of 2010 and $1,767 million for the third quarter of 2011. The increase in cash flow from operations for the year ended December 31, 2011 from the year ended December 31, 2010 was primarily due to:

- higher North America crude oil and NGL sales volumes;
- higher crude oil and NGL netbacks; and
- lower net interest and other financing costs;

partially offset by:

- the impact of suspension of production at Horizon, net of business interruption insurance;
- lower natural gas netbacks;
- realized risk management losses;
- the impact of a stronger Canadian dollar; and
- higher cash taxes.

The increase in cash flow from operations from the fourth quarter of 2010 was primarily due to:

- higher North America and Horizon crude oil and NGL sales volumes;
- higher crude oil and NGL netbacks;
- lower net interest and other financing costs; and
- the impact of a weaker Canadian dollar;

partially offset by:

- lower natural gas netbacks; and
- higher cash taxes.

The increase in cash flow from operations from the third quarter of 2011 was primarily due to:

- higher Horizon crude oil and NGL sales volumes;
- higher crude oil and NGL netbacks; and
- the impact of a weaker Canadian dollar;

partially offset by:

- lower North America crude oil and NGL sales volumes;
- lower natural gas netbacks;
- realized risk management losses; and
- higher cash taxes.

Total production before royalties for the year ended December 31, 2011 decreased 5% to 598,526 BOE/d from 632,191 BOE/d for the year ended December 31, 2010. Total production before royalties for the fourth quarter of 2011 increased by 2% to 657,599 BOE/d from 647,441 BOE/d for the fourth quarter of 2010 and increased by 7% from 612,575 BOE/d for the third quarter of 2011. Production for the fourth quarter of 2011 was within the Company's previously issued guidance.

SUMMARY OF QUARTERLY RESULTS

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

($ millions, except per common share amounts)		**Dec 31 2011**		Sep 30 2011		Jun 30 2011		Mar 31 2011
Product sales	**$**	**4,788**	$	3,690	$	3,727	$	3,302
Net earnings	**$**	**832**	$	836	$	929	$	46
Net earnings per common share								
– basic	**$**	**0.76**	$	0.76	$	0.85	$	0.04
– diluted	**$**	**0.76**	$	0.76	$	0.84	$	0.04

($ millions, except per common share amounts)		Dec 31 2010		Sep 30 2010		Jun 30 2010		Mar 31 2010(1)
Product sales	$	3,787	$	3,341	$	3,614	$	3,580
Net earnings (loss)	$	(309)	$	596	$	651	$	735
Net earnings (loss) per common share								
– basic	$	(0.28)	$	0.54	$	0.60	$	0.68
– diluted	$	(0.28)	$	0.54	$	0.60	$	0.67

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

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 of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America, and the suspension and recommencement of production at both Horizon and the Olowi field in Offshore Gabon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, proved reserves, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the impact of the suspension and recommencement of operations at Horizon and the impact of impairments at the Olowi field in Offshore Gabon.

- **Share-based compensation** – Fluctuations due to the mark-to-market movements of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Changes in the Canadian dollar relative to the US dollar 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 or enacted in the various periods.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
WTI benchmark price (US$/bbl) (1)	**$ 94.02**	$ 89.81	$ 85.18	**$ 95.14**	$ 79.55
Dated Brent benchmark price (US$/bbl)	**$ 109.29**	$ 113.46	$ 86.49	**$ 111.29**	$ 79.50
WCS blend differential from WTI (US$/bbl)	**$ 10.49**	$ 17.66	$ 18.15	**$ 17.10**	$ 14.26
WCS blend differential from WTI (%)	**11%**	20%	21%	**18%**	18%
SCO price (US$/bbl) (2)	**$ 102.95**	$ 100.64	$ 83.14	**$ 103.63**	$ 78.56
Condensate benchmark price (US$/bbl)	**$ 108.68**	$ 101.73	$ 85.18	**$ 105.38**	$ 81.81
NYMEX benchmark price (US$/MMBtu)	**$ 3.61**	$ 4.19	$ 3.81	**$ 4.07**	$ 4.42
AECO benchmark price (C$/GJ)	**$ 3.29**	$ 3.53	$ 3.39	**$ 3.48**	$ 3.91
US/Canadian dollar average exchange rate (US$)	**$ 0.9773**	$ 1.0197	$ 0.9874	**$ 1.0111**	$ 0.9709

(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$95.14 per bbl for the year ended December 31, 2011, an increase of 20% from US$79.55 per bbl for the year ended December 31, 2010. WTI averaged US$94.02 per bbl for the fourth quarter of 2011, an increase of 10% from US$85.18 per bbl for the fourth quarter of 2010, and an increase of 5% from US$89.81 per bbl for the third quarter of 2011. The increase in the WTI benchmark price for the year ended December 31, 2011 was reflective of the political instability in the Middle East and North Africa and continued strong Asian demand. The increase in the WTI benchmark price for the fourth quarter of 2011, compared to the third quarter of 2011, was partially due to the announcement of the Seaway pipeline reversal from Cushing to the Gulf Coast, offset by the relative strength of the US dollar.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$111.29 per bbl for the year ended December 31, 2011, an increase of 40% compared to US$79.50 per bbl for the year ended December 31, 2010. Brent averaged US$109.29 per bbl for the fourth quarter of 2011, an increase of 26% compared to US$86.49 per bbl for the fourth quarter of 2010 and a decrease of 4% from US$113.46 per bbl for the third quarter of 2011. The higher Dated Brent ("Brent") pricing relative to WTI in 2011 from the comparable periods in 2010 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 lower WTI priced barrels delivered into the PADD II from obtaining United States Gulf Coast Brent-based pricing.

The Western Canadian Select ("WCS") Heavy Differential averaged 18% for the year ended December 31, 2011, comparable to the year ended December 31, 2010. The WCS Heavy Differential averaged 11% for the fourth quarter of 2011, compared to 21% in the fourth quarter of 2010, and 20% for the third quarter of 2011. The WCS Heavy Differential narrowed in the fourth quarter of 2011, compared to the third quarter of 2011, as a result of increased heavy crude oil conversion from new coking capacity added to key PADD II refineries.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During 2011, condensate prices traded at a premium to WTI, reflecting the tight supply situation.

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, logistics and refinery margins.

NYMEX natural gas prices averaged US$4.07 per MMBtu for the year ended December 31, 2011, a decrease of 8% from US$4.42 per MMBtu for the year ended December 31, 2010. NYMEX natural gas prices averaged US$3.61 per MMBtu for the fourth quarter of 2011, a decrease of 5% from US$3.81 per MMBtu for the fourth quarter of 2010, and a decrease of 14% from US$4.19 per MMBtu for the third quarter of 2011. AECO natural gas prices for the year ended December 31, 2011 averaged $3.48 per GJ, a decrease of 11% from $3.91 per GJ for the year ended December 31, 2010. AECO natural gas prices for the fourth quarter of 2011 averaged $3.29 per GJ, a decrease of 3% from $3.39 per GJ for the fourth quarter of 2010, and a decrease of 7% from $3.53 per GJ for the third 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 fourth quarter of 2011 as a result of warmer than normal winter temperatures.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**291,839**	304,671	286,698	**295,618**	270,562
North America – Oil Sands Mining and Upgrading	**102,952**	50,354	92,730	**40,434**	90,867
North Sea	**26,769**	26,350	31,701	**29,992**	33,292
Offshore Africa	**22,726**	22,525	27,706	**23,009**	30,264
	444,286	403,900	438,835	**389,053**	424,985
Natural gas (MMcf/d)					
North America	**1,255**	1,226	1,223	**1,231**	1,217
North Sea	**6**	5	9	**7**	10
Offshore Africa	**19**	21	20	**19**	16
	1,280	1,252	1,252	**1,257**	1,243
Total barrels of oil equivalent (BOE/d)	**657,599**	612,575	647,441	**598,526**	632,191
Product mix					
Light and medium crude oil and NGLs	**17%**	17%	17%	**18%**	18%
Pelican Lake heavy crude oil	**6%**	6%	6%	**6%**	6%
Primary heavy crude oil	**17%**	17%	15%	**18%**	15%
Bitumen (thermal oil)	**12%**	18%	16%	**16%**	14%
Synthetic crude oil	**16%**	8%	14%	**7%**	14%
Natural gas	**32%**	34%	32%	**35%**	33%
Percentage of product sales (1) (excluding midstream revenue)					
Crude oil and NGLs	**90%**	85%	88%	**86%**	85%
Natural gas	**10%**	15%	12%	**14%**	15%

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**230,522**	251,909	223,034	**240,006**	219,736
North America – Oil Sands Mining and Upgrading	**98,287**	48,509	89,530	**38,721**	87,763
North Sea	**26,714**	26,284	31,644	**29,919**	33,227
Offshore Africa	**19,331**	18,452	25,291	**20,532**	28,288
	374,854	345,154	369,499	**329,178**	369,014
Natural gas (MMcf/d)					
North America	**1,211**	1,189	1,206	**1,186**	1,168
North Sea	**6**	5	9	**7**	10
Offshore Africa	**16**	17	18	**16**	15
	1,233	1,211	1,233	**1,209**	1,193
Total barrels of oil equivalent (BOE/d)	**580,242**	546,861	574,959	**530,576**	567,743

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 year ended December 31, 2011 decreased 8% to 389,053 bbl/d from 424,985 bbl/d for the year ended December 31, 2010. Crude oil and NGLs production for the fourth quarter of 2011 increased 1% to 444,286 bbl/d from 438,835 bbl/d for the fourth quarter of 2010 and increased 10% from 403,900 bbl/d for the third quarter of 2011. The decrease in production for the year ended December 31, 2011 from the comparable period in 2010 was primarily related to the suspension of production at Horizon, partially offset by the impact of a record heavy crude oil drilling program and the cyclic nature of the Company's thermal operations. The increase from the third quarter of 2011 was primarily due to higher production at Horizon. Crude oil and NGLs production in the fourth quarter of 2011 was within the Company's previously issued guidance of 430,000 to 461,000 bbl/d.

Natural gas production for the year ended December 31, 2011 averaged 1,257 MMcf/d compared to 1,243 MMcf/d for the year ended December 31, 2010. Natural gas production for the fourth quarter of 2011 increased by 2% to 1,280 MMcf/d from 1,252 MMcf/d in both the fourth quarter of 2010 and in the third quarter of 2011. The increase in natural gas production from the comparable periods in 2010 reflects the new production volumes from natural gas producing properties acquired during 2010 and 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. During the fourth quarter of 2011, the Company completed a pipeline to a deep cut gas facility, which increased Septimus liquids recoveries. Natural gas production in the fourth quarter of 2011 was at the low end of the Company's previously issued guidance of 1,279 to 1,304 MMcf/d.

For 2012, revised annual production guidance is targeted to average between 440,000 and 480,000 bbl/d of crude oil and NGLs and between 1,247 and 1,297 MMcf/d of natural gas. First quarter 2012 production guidance is targeted to average between 367,000 and 400,000 bbl/d of crude oil and NGLs and between 1,300 and 1,320 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2011 increased 9% to average 295,618 bbl/d from 270,562 bbl/d for the year ended December 31, 2010. For the fourth quarter of 2011, crude oil and NGLs production increased 2% to average 291,839 bbl/d, compared to 286,698 bbl/d for the fourth quarter of 2010, and decreased 4% compared to 304,671 bbl/d for the third quarter of 2011. Increases in crude oil and NGLs production from comparable periods in 2010 were primarily due to the impact of a record heavy crude oil drilling program and the cyclic nature of the Company's thermal operations. The Company’s heavy oil drilling continues on track and exited 2011 at over 115,000 bbl/d, an increase of approximately 19% compared to the first quarter of 2011. The decrease in production from the third quarter of 2011 was due to low bitumen oil production 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 277,000 bbl/d to 297,000 bbl/d for the fourth quarter of 2011.

Natural gas production for the year ended December 31, 2011 increased 1% to 1,231 MMcf/d compared to 1,217 MMcf/d for the year ended December 31, 2010. Natural gas production increased 3% to 1,255 MMcf/d for the fourth quarter of 2011 compared to 1,223 MMcf/d in the fourth quarter of 2010 and increased 2% compared to 1,226 MMcf/d in the third quarter of 2011. Natural gas production for the three months and year ended December 31, 2011 reflected new production volumes from natural gas producing properties acquired during 2010 and 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. Production of natural gas was at the low end of the Company’s previously issued guidance of 1,255 MMcf/d to 1,275 MMcf/d for the fourth quarter of 2011.

North America – Oil Sands Mining and Upgrading

As a result of a fire at Horizon’s primary upgrading coking plant on January 6, 2011, all SCO production was suspended. On August 16, 2011, the Company successfully and safely recommenced operations. First pipeline deliveries commenced on August 18, 2011. As a result, production averaged 40,434 bbl/d for the year ended December 31, 2011, compared to 90,867 bbl/d for the year ended December 31, 2010. Subsequent to December 31, 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. The Company has targeted mid to late March to return to full production levels. Cost estimates for the repair are not expected to be significant.

North Sea

North Sea crude oil production for the year ended December 31, 2011 decreased 10% to 29,992 bbl/d from 33,292 bbl/d for the year ended December 31, 2010. Fourth quarter 2011 North Sea crude oil production decreased 16% to 26,769 bbl/d from 31,701 bbl/d for the fourth quarter of 2010, and increased 2% from 26,350 bbl/d for the third quarter of 2011. The decrease in production volumes from the comparable periods in 2010 was due to natural field declines and timing of scheduled maintenance shutdowns. 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 vessel 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. As a result of this incident, production in the fourth quarter of 2011 was slightly below the Company’s previously issued guidance of 28,000 bbl/d to 30,000 bbl/d.

Offshore Africa

Offshore Africa crude oil production decreased 24% to 23,009 bbl/d for the year ended December 31, 2011 from 30,264 bbl/d for the year ended December 31, 2010. Fourth quarter crude oil production averaged 22,726 bbl/d, decreasing 18% from 27,706 bbl/d for the fourth quarter of 2010 and was comparable to the third quarter of 2011. The decrease in production volumes from the comparable periods in 2010 was due to natural field declines and the payout of the Baobab field in May 2011. Production in the fourth quarter was within the Company's previously issued guidance of 20,000 bbl/d to 24,000 bbl/d.

2012 Guidance

The Company’s 2012 annual crude oil and NGL production guidance is 320,000 to 340,000 bbl/d for North America, 85,000 to 95,000 bbl/d for North America – Oil Sands Mining and Upgrading and 35,000 to 45,000 bbl/d for the North Sea and Offshore Africa.

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)	**Dec 31 2011**	Sep 30 2011	Dec 31 2010
North America – Exploration and Production	**557,475**	825,048	761,351
North America – Oil Sands Mining and Upgrading (SCO)	**1,021,236**	1,091,012	1,172,200
North Sea	**286,633**	580,101	264,995
Offshore Africa	**527,312**	1,207,124	404,197
	2,392,656	3,703,285	2,602,743

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 85.28**	$ 73.80	$ 67.74	**$ 77.46**	$ 65.81
Royalties	**15.53**	11.52	12.14	**12.30**	10.09
Production expense	**16.85**	16.42	13.59	**15.75**	14.16
Netback	**$ 52.90**	$ 45.86	$ 42.01	**$ 49.41**	$ 41.56
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 3.50**	$ 3.76	$ 3.56	**$ 3.73**	$ 4.08
Royalties	**0.18**	0.17	0.07	**0.18**	0.20
Production expense	**1.15**	1.15	1.05	**1.15**	1.09
Netback	**$ 2.17**	$ 2.44	$ 2.44	**$ 2.40**	$ 2.79
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 61.21**	$ 55.19	$ 50.41	**$ 57.16**	$ 49.90
Royalties	**10.14**	7.59	7.83	**8.12**	6.72
Production expense	**13.12**	12.83	10.91	**12.42**	11.25
Netback	**$ 37.95**	$ 34.77	$ 31.67	**$ 36.62**	$ 31.93

(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			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 81.02**	$ 67.81	$ 63.62	**$ 72.17**	$ 62.28
North Sea	**$ 109.71**	$ 109.28	$ 88.05	**$ 108.56**	$ 82.49
Offshore Africa	**$ 102.74**	$ 114.44	$ 80.39	**$ 105.53**	$ 78.93
Company average	**$ 85.28**	$ 73.80	$ 67.74	**$ 77.46**	$ 65.81
Natural gas ($/Mcf) (1) (2)					
North America	**$ 3.36**	$ 3.67	$ 3.50	**$ 3.64**	$ 4.05
North Sea	**$ 4.17**	$ 3.26	$ 2.99	**$ 4.07**	$ 3.83
Offshore Africa	**$ 12.79**	$ 9.38	$ 7.59	**$ 9.56**	$ 6.63
Company average	**$ 3.50**	$ 3.76	$ 3.56	**$ 3.73**	$ 4.08
Company average ($/BOE) (1) (2)	**$ 61.21**	$ 55.19	$ 50.41	**$ 57.16**	$ 49.90

(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 increased 16% to average $72.17 per bbl for the year ended December 31, 2011 from $62.28 per bbl for the year ended December 31, 2010. North America realized crude oil prices averaged $81.02 per bbl for the fourth quarter of 2011, an increase of 27% compared to $63.62 per bbl for the fourth quarter of 2010 and an increase of 19% compared to $67.81 per bbl for the third quarter of 2011. The increase in prices for the year ended December 31, 2011 from the comparable period in 2010 was primarily a result of higher WTI benchmark pricing, partially offset by the impact of a stronger Canadian dollar relative to the US dollar. The increase in prices for the three months ended December 31, 2011 compared to the three months ended December 31, 2010 and the third 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 Company continues to focus on its crude oil blending marketing strategy, and in the fourth quarter of 2011 contributed approximately 150,000 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 for 2012.

North America realized natural gas prices decreased 10% to average $3.64 per Mcf for the year ended December 31, 2011 from $4.05 per Mcf for the year ended December 31, 2010. North America realized natural gas prices decreased 4% to average $3.36 per Mcf for the fourth quarter of 2011, compared to $3.50 per Mcf in the fourth quarter of 2010, and decreased 8% compared to $3.67 per Mcf for the third quarter of 2011. The decrease in natural gas prices for the three months and year ended December 31, 2011 from the comparable periods in 2010 and the third quarter of 2011 was primarily due to lower NYMEX and AECO benchmark pricing related to the impact of strong supply from US shale projects.

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

(Quarterly Average)	**Dec 31 2011**	Sep 30 2011	Dec 31 2010
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 86.05**	$ 78.54	$ 69.77
Pelican Lake heavy crude oil ($/bbl)	**$ 81.64**	$ 66.33	$ 61.73
Primary heavy crude oil ($/bbl)	**$ 79.91**	$ 65.08	$ 62.62
Bitumen (thermal oil) ($/bbl)	**$ 78.38**	$ 65.31	$ 62.10
Natural gas ($/Mcf)	**$ 3.36**	$ 3.67	$ 3.50

(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 increased 32% to average $108.56 per bbl for the year ended December 31, 2011 from $82.49 per bbl for the year ended December 31, 2010. Realized crude oil prices averaged $109.71 per bbl for the fourth quarter of 2011, an increase of 25% from $88.05 per bbl for the fourth quarter of 2010, and were comparable to the third quarter of 2011. The increase in realized crude oil prices in the North Sea for the year ended December 31, 2011 from the comparable period in 2010 was primarily the result of fluctuations in Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar. The increase in realized crude oil prices in the North Sea for the three months ended December 31, 2011 from the comparable period in 2010 was primarily the result of fluctuations in Brent benchmark pricing and the US dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 34% to average $105.53 per bbl for the year ended December 31, 2011 from $78.93 per bbl for the year ended December 31, 2010. Realized crude oil prices averaged $102.74 per bbl for the fourth quarter of 2011, an increase of 28% from $80.39 per bbl for the fourth quarter of 2010, and a decrease of 10% from $114.44 per bbl in the third quarter of 2011. The increase in realized crude oil prices in Offshore Africa for the year ended December 31, 2011 from the comparable period in 2010 was primarily the result of fluctuations in Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar. The increase in realized crude oil prices in Offshore Africa for the three months ended December 31, 2011 from the comparable period in 2010 was primarily the result of fluctuations in Brent benchmark pricing, together with the impact of the weaker Canadian dollar. The decrease in realized crude oil prices from the third quarter of 2011 was primarily the result of fluctuations in Brent benchmark pricing and the US dollar and the timing of liftings.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 17.10**	$ 11.78	$ 14.30	**$ 13.51**	$ 11.85
North Sea	**$ 0.23**	$ 0.27	$ 0.16	**$ 0.26**	$ 0.16
Offshore Africa	**$ 15.35**	$ 20.69	$ 7.01	**$ 12.47**	$ 5.54
Company average	**$ 15.53**	$ 11.52	$ 12.14	**$ 12.30**	$ 10.09
Natural gas ($/Mcf) (1)					
North America	**$ 0.15**	$ 0.15	$ 0.06	**$ 0.16**	$ 0.20
Offshore Africa	**$ 2.33**	$ 1.90	$ 0.69	**$ 1.59**	$ 0.53
Company average	**$ 0.18**	$ 0.17	$ 0.07	**$ 0.18**	$ 0.20
Company average ($/BOE) (1)	**$ 10.14**	$ 7.59	$ 7.83	**$ 8.12**	$ 6.72

(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 year ended December 31, 2011 compared to 2010 reflected benchmark commodity prices.

Crude oil and NGLs royalties averaged approximately 19% of product sales in 2011 and were comparable to 2010. Crude oil and NGLs royalties averaged approximately 21% of product sales for the fourth quarter of 2011 compared to 22% for the fourth quarter of 2010 and 17% for the third 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 4% of product sales in 2011, compared to 5% in 2010. Natural gas royalties averaged approximately 4% of product sales for the fourth quarter of 2011, compared to 2% for the fourth quarter of 2010 and 4% for the third 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 17% in 2011 compared to 7% in 2010. Royalty rates as a percentage of product sales averaged approximately 18% for the fourth quarter of 2011 compared to 9% for the fourth quarter of 2010 and 18% for the third quarter of 2011. The increase in royalty rates in 2011 was due to payout of the Baobab field and higher crude oil prices during the year. Offshore Africa royalty rates are anticipated to average 13% to 15% for 2012.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 14.32**	$ 13.38	$ 11.41	**$ 13.21**	$ 12.14
North Sea	**$ 36.45**	$ 49.72	$ 30.05	**$ 37.06**	$ 29.73
Offshore Africa	**$ 22.16**	$ 19.91	$ 13.86	**$ 20.72**	$ 14.64
Company average	**$ 16.85**	$ 16.42	$ 13.59	**$ 15.75**	$ 14.16
Natural gas ($/Mcf) (1)					
North America	**$ 1.12**	$ 1.13	$ 1.02	**$ 1.12**	$ 1.06
North Sea	**$ 3.51**	$ 2.68	$ 2.70	**$ 2.83**	$ 2.91
Offshore Africa	**$ 2.52**	$ 2.16	$ 2.00	**$ 2.03**	$ 1.76
Company average	**$ 1.15**	$ 1.15	$ 1.05	**$ 1.15**	$ 1.09
Company average ($/BOE) (1)	**$ 13.12**	$ 12.83	$ 10.91	**$ 12.42**	$ 11.25

(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 year ended December 31, 2011 increased 9% to $13.21 per bbl from $12.14 per bbl for the year ended December 31, 2010. North America crude oil and NGLs production expense for the fourth quarter of 2011 increased 26% to $14.32 per bbl from $11.41 per bbl for the fourth quarter of 2010 and increased 7% from $13.38 per bbl for the third quarter of 2011. The increase in production expense per barrel from the fourth quarter of 2010 and the third quarter of 2011 was a result of higher overall service costs relating to heavy crude oil production and the timing of thermal steam cycles. North America crude oil and NGLs production expense was slightly higher than the Company's previously issued guidance of $12.00 per bbl to $13.00 per bbl, and is anticipated to average $11.00 to $13.00 per bbl for 2012.

North America natural gas production expense for the year ended December 31, 2011 increased 6% to $1.12 per Mcf from $1.06 per Mcf for the year ended December 31, 2010. North America natural gas production expense for the fourth quarter of 2011 increased 10% to $1.12 per Mcf from $1.02 per Mcf for the fourth quarter of 2010, and was comparable to the third quarter of 2011. Natural gas production expense increased from the comparable periods in 2010 due to acquisitions of natural gas producing properties that have higher operating costs per Mcf than the Company’s existing properties. North America natural gas production expense was within the Company's previously issued guidance of $1.08 per Mcf to $1.14 per Mcf, and is anticipated to average $1.10 to $1.20 per Mcf for 2012.

North Sea

North Sea crude oil production expense for the year ended December 31, 2011 increased 25% to $37.06 per bbl from $29.73 per bbl for the year ended December 31, 2010. North Sea crude oil production expense for the fourth quarter of 2011 increased 21% to $36.45 per bbl from $30.05 per bbl for the fourth quarter of 2010, and decreased 27% from $49.72 per bbl for the third quarter of 2011. Production expense increased on a per barrel basis from the comparable periods in 2010 due to lower production volumes on relatively fixed costs and increased fuel prices. Production expense decreased on a per barrel basis from the third quarter of 2011 due to higher costs associated with the planned shutdowns in the third quarter of 2011. North Sea crude oil production expense was within the Company's previously issued guidance of $37.00 per bbl to $38.00 per bbl, and is anticipated to average $43.00 to $48.00 per bbl for 2012.

Offshore Africa

Offshore Africa crude oil production expense for the year ended December 31, 2011 increased 42% to $20.72 per bbl from $14.64 per bbl for the year ended December 31, 2010. Offshore Africa crude oil production expense for the fourth quarter of 2011 averaged $22.16 per bbl, an increase of 60% compared to $13.86 per bbl for the fourth quarter of 2010 and an increase of 11% compared to $19.91 per bbl for the third quarter of 2011. Production expense increased on a per barrel basis from the comparable periods in 2010 due to lower production volumes on relatively fixed costs. Production expense for the fourth quarter of 2011 was higher than the third quarter of 2011 due to the timing of liftings for each field. Offshore Africa crude oil production expense was slightly below the Company's previously issued guidance of $21.00 per bbl to $22.00 per bbl, and is anticipated to average $27.00 to $29.00 per bbl for 2012.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Expense ($ millions)	**$ 863**	$ 809	$ 1,440	**$ 3,331**	$ 3,716
$/BOE (1)	**$ 16.51**	$ 15.96	$ 27.66	**$ 16.35**	$ 18.76

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

Depletion, depreciation and amortization expense decreased for the three months and year ended December 31, 2011 from the comparable periods in 2010 due to lower sales volumes in the North Sea and Offshore Africa, and the impact of an asset impairment related to Gabon, Offshore Africa at December 31, 2010, partially offset by higher sales volumes in North America. The increase in depletion, depreciation and amortization expense for the three months ended December 31, 2011 from the third quarter of 2011 was primarily due to the impact of higher sales volumes in the North Sea and Offshore Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Expense ($ millions)	**$ 28**	$ 28	$ 24	**$ 110**	$ 95
$/BOE (1)	**$ 0.54**	$ 0.54	$ 0.45	**$ 0.54**	$ 0.47

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

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

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

On January 6, 2011, the Company suspended SCO production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. The Company successfully and safely recommenced operations on August 16, 2011. First pipeline deliveries commenced on August 18, 2011. As a result, production averaged 40,434 bbl/d for the year ended December 31, 2011, compared to 90,867 bbl/d for the year ended December 31, 2010.

Subsequent to December 31, 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. The Company has targeted mid to late March to return to full production levels. Cost estimates for the repair are not expected to be significant.

PRODUCT PRICES AND ROYALTIES – OIL SANDS MINING AND UPGRADING

($/bbl) (1)	Three Months Ended **Dec 31 2011**	 Sep 30 2011	 Dec 31 2010	Year Ended **Dec 31 2011**	 Dec 31 2010
SCO sales price (2)	**$ 103.16**	$ 96.19	$ 81.51	**$ 99.74**	$ 77.89
Bitumen value for royalty purposes (3)	**$ 69.91**	$ 56.54	$ 56.42	**$ 61.86**	$ 56.14
Bitumen royalties (4)	**$ 4.21**	$ 3.48	$ 2.77	**$ 3.99**	$ 2.72

(1) Amounts expressed on a per unit basis in 2011 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 $99.74 per bbl for the year ended December 31, 2011, an increase of 28% compared to $77.89 per bbl for the year ended December 31, 2010. Realized SCO sales prices averaged $103.16 per bbl for the fourth quarter of 2011, an increase of 27% compared to $81.51 per bbl for the fourth quarter of 2010, and an increase of 7% compared to $96.19 per bbl in the third quarter of 2011.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

($ millions)	Three Months Ended **Dec 31 2011**	 Sep 30 2011	 Dec 31 2010	Year Ended **Dec 31 2011**	 Dec 31 2010
Cash costs	**$ 344**	$ 306	$ 304	**$ 1,127**	$ 1,208
Less: costs incurred during the period of suspension of production	**–**	(151)	–	**(581)**	–
Adjusted cash costs	**$ 344**	$ 155	$ 304	**$ 546**	$ 1,208
Adjusted cash costs, excluding natural gas costs	**$ 316**	$ 144	$ 278	**$ 502**	$ 1,082
Adjusted natural gas costs	**28**	11	26	**44**	126
Adjusted cash production costs	**$ 344**	$ 155	$ 304	**$ 546**	$ 1,208

($/bbl) (1)	Three Months Ended **Dec 31 2011**	 Sep 30 2011	 Dec 31 2010	Year Ended **Dec 31 2011**	 Dec 31 2010
Adjusted cash costs, excluding natural gas costs	**$ 33.11**	$ 33.13	$ 33.09	**$ 33.68**	$ 32.58
Adjusted natural gas costs	**2.93**	2.72	3.04	**2.96**	3.78
Adjusted cash production costs	**$ 36.04**	$ 35.85	$ 36.13	**$ 36.64**	$ 36.36
Sales (bbl/d)	**103,710**	47,218	91,350	**40,847**	91,010

(1) Amounts expressed on a per unit basis in 2011 are based on sales volumes excluding the period during suspension of production.

Adjusted cash production costs averaged $36.64 per bbl for the year ended December 31, 2011, an increase of 1% compared to $36.36 per bbl for the year ended December 31, 2010. Adjusted cash production costs for the fourth quarter of 2011 averaged $36.04 per bbl, comparable to the fourth quarter of 2010 and the third quarter of 2011.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2011**	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Depletion, depreciation and amortization	**$ 133**	$ 77	$ 104	**$ 266**	$ 396
Less: depreciation incurred during the period of suspension of production	**–**	(21)	–	**(64)**	–
Adjusted depletion, depreciation and amortization	**$ 133**	$ 56	$ 104	**$ 202**	$ 396
$/bbl (1)	**$ 13.91**	$ 13.00	$ 12.37	**$ 13.54**	$ 11.91

(1) Amounts expressed on a per unit basis in 2011 are based on sales volumes excluding the period during suspension of production.

Adjusted depletion, depreciation and amortization expense for the year ended December 31, 2011 decreased from the year ended December 31, 2010 primarily due to the impact of the Horizon suspension from January 6, 2011 to August 18, 2011. Depletion, depreciation and amortization expense for the fourth quarter of 2011 increased compared to the three months ended December 31, 2010 and the third quarter of 2011 due to higher sales volumes and the impact of depreciation determined on a straight-line basis.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Expense ($ millions)	**$ 5**	$ 5	$ 7	**$ 20**	$ 28
$/bbl (1)	**$ 0.52**	$ 1.14	$ 0.87	**$ 1.33**	$ 0.88

(1) Amounts expressed on a per unit basis in 2011 are based on sales volumes.

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

MIDSTREAM

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2011**	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Revenue	**$ 22**	$ 23	$ 20	**$ 88**	$ 79
Production expense	**7**	7	6	**26**	22
Midstream cash flow	**15**	16	14	**62**	57
Depreciation	**2**	1	2	**7**	8
Segment earnings before taxes	**$ 13**	$ 15	$ 12	**$ 55**	$ 49

Midstream operating results were consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Expense ($ millions)	**$ 47**	$ 65	$ 54	**$ 235**	$ 211
$/BOE [1]	**$ 0.76**	$ 1.17	$ 0.89	**$ 1.07**	$ 0.92

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

Administration expense for the year ended December 31, 2011 increased from the comparable period in 2010 primarily due to higher staffing related costs. Administration expense for the fourth quarter of 2011 decreased from the comparable period in 2010 and the third quarter of 2011 due to higher capital and operating recoveries.

SHARE-BASED COMPENSATION

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2011**	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Expense (recovery)	**$ 207**	$ (249)	$ 266	**$ (102)**	$ 203

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

The Company recorded a $102 million share-based compensation recovery for the year ended December 31, 2011 primarily as a result of remeasurement of the fair value of outstanding options at the end of the period, related to a decrease in the Company's share price, offset by normal course graded vesting of options granted in prior periods and the impact of vested options exercised or surrendered during the period. For the year ended December 31, 2011, no amounts were capitalized in respect of share-based compensation to Oil Sands Mining and Upgrading (December 31, 2010 – capitalized $32 million).

For the year ended December 31, 2011, the Company paid $14 million for stock options surrendered for cash settlement (December 31, 2010 – $45 million).

INTEREST AND OTHER FINANCING COSTS

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2011**	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Expense, gross	**$ 102**	$ 113	$ 129	**$ 432**	$ 476
Less: capitalized interest	**19**	16	9	**59**	28
Expense, net	**$ 83**	$ 97	$ 120	**$ 373**	$ 448
$/BOE [1]	**$ 1.35**	$ 1.75	$ 2.00	**$ 1.71**	$ 1.94
Average effective interest rate	**4.7%**	4.6%	5.3%	**4.7%**	4.9%

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

Gross interest and other financing costs for the year ended December 31, 2011 decreased compared to 2010 due to the impact of a stronger Canadian dollar on US dollar denominated debt, partially offset by higher average debt levels and variable interest rates. Gross interest and other financing costs for the fourth quarter of 2011 decreased compared to the fourth quarter of 2010 and the third quarter of 2011 due to lower interest costs on fixed-rate debt, partially offset by higher average debt levels and the impact of a weaker Canadian dollar on US dollar denominated debt. Capitalized interest for the year ended December 31, 2011 increased from the comparable period in 2010 due to additional amounts relating to Horizon and the Kirby Project.

The Company's average effective interest rates for the three months and year ended December 31, 2011 decreased from the comparable periods in 2010 primarily due to settlement of the US$400 million 6.70% US dollar denominated debt securities and subsequent issuance of US dollar denominated debt securities at interest rates of 1.45% and 3.45%. The effective interest rate for the three months ended December 31, 2011 was comparable to the third quarter of 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.

($ millions)	Three Months Ended Dec 31 2011	Sep 30 2011	Dec 31 2010	Year Ended Dec 31 2011	Dec 31 2010
Crude oil and NGLs financial instruments	**$ 27**	$ 26	$ 47	**$ 117**	$ 84
Natural gas financial instruments	**–**	–	(53)	**–**	(234)
Foreign currency contracts and interest rate swaps	**(7)**	(49)	18	**(16)**	40
Realized loss (gain)	**$ 20**	$ (23)	$ 12	**$ 101**	$ (110)
Crude oil and NGLs financial instruments	**$ 5**	$ (71)	$ 108	**$ (134)**	$ (108)
Natural gas financial instruments	**–**	–	52	**–**	72
Foreign currency contracts and interest rate swaps	**53**	(51)	20	**6**	12
Unrealized loss (gain)	**$ 58**	$ (122)	$ 180	**$ (128)**	$ (24)
Net loss (gain)	**$ 78**	$ (145)	$ 192	**$ (27)**	$ (134)

Complete details related to outstanding derivative financial instruments at December 31, 2011 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

The Company recorded a net unrealized gain of $128 million ($95 million after-tax) on its risk management activities for the year ended December 31, 2011, including an unrealized loss of $58 million ($50 million after-tax) for the fourth quarter of 2011 (September 30, 2011 – unrealized gain of $122 million, $97 million after-tax; December 31, 2010 – unrealized loss of $180 million, $136 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

($ millions)	Three Months Ended Dec 31 2011	Sep 30 2011	Dec 31 2010	Year Ended Dec 31 2011	Dec 31 2010
Net realized loss (gain)	**$ 11**	$ (243)	$ 6	**$ (214)**	$ (2)
Net unrealized (gain) loss(1)	**(117)**	454	(116)	**215**	(161)
Net (gain) loss	**$ (106)**	$ 211	$ (110)	**$ 1**	$ (163)

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

The net unrealized foreign exchange loss for the year ended December 31, 2011 was primarily due to the reversal of the unrealized foreign exchange gain on the settlement of the US$400 million 6.70% US dollar denominated debt securities in the third quarter of 2011, together with the weakening of the Canadian dollar at December 31, 2011 with respect to US dollar denominated debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2011 – unrealized loss of $43 million, September 30, 2011 – unrealized gain of $150 million, December 31, 2010 – unrealized loss of $71 million; year ended December 31, 2011 – unrealized gain of $43 million, December 31, 2010 – unrealized loss of $101 million). The net realized foreign exchange gain for the year ended December 31, 2011 was primarily due to the settlement of the US$400 million 6.70% US dollar denominated debt securities in the third quarter of 2011, partially offset by foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the fourth quarter at US$0.9833 (September 30, 2011- US$0.9626; December 31, 2010 – US$1.0054).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Dec 31 2011	Sep 30 2011	Dec 31 2010	Year Ended Dec 31 2011	Dec 31 2010
North America [(1)]	**$ 119**	$ 26	$ 49	**$ 315**	$ 431
North Sea	**84**	45	84	**245**	203
Offshore Africa	**50**	46	23	**140**	64
PRT expense – North Sea	**39**	42	14	**135**	68
Other taxes	**7**	6	6	**25**	23
Current income tax	**299**	165	176	**860**	789
Deferred income tax expense	**157**	157	65	**412**	408
Deferred PRT expense – North Sea	**(13)**	(4)	(11)	**(5)**	(9)
Deferred income tax	**144**	153	54	**407**	399
	443	318	230	**1,267**	1,188
Income tax rate and other legislative changes [(2)]	**–**	–	–	**(104)**	(132)
	$ 443	$ 318	$ 230	**$ 1,163**	$ 1,056
Effective income tax rate on adjusted net earnings from operations[(3)]	**30.1%**	25.7%	33.4%	**27.7%**	28.9%

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

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

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

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.

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. In its 2011 budget, the UK government announced its intention to restrict tax relief on decomisssioning expenditures to 50% for non-PRT fields and 75% for PRT fields. The proposed legislation to effect that restriction was released in 2011 for enactment in 2012. This proposed tax change would result in a deferred tax charge currently estimated at $56 million.

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

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 $700 million to $800 million in Canada and $200 million to $300 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [(1)]

($ millions)	Three Months Ended Dec 31 2011	Three Months Ended Sep 30 2011	Three Months Ended Dec 31 2010	Year Ended Dec 31 2011	Year Ended Dec 31 2010
Exploration and Evaluation					
Net expenditures	**$ 112**	$ 85	$ 409	**$ 312**	$ 572
Property, Plant and Equipment					
Net property acquisitions	**396**	127	489	**1,012**	1,482
Land acquisition and retention	**12**	12	12	**44**	41
Seismic evaluations	**9**	12	17	**47**	51
Well drilling, completion and equipping	**585**	437	443	**1,878**	1,499
Production and related facilities	**480**	415	311	**1,690**	1,122
Capitalized interest	**5**	4	–	**13**	–
Net expenditures	**1,487**	1,007	1,272	**4,684**	4,195
Total Exploration and Production	**1,599**	1,092	1,681	**4,996**	4,767
Oil Sands Mining and Upgrading:					
Horizon Phases 2/3 construction costs	**150**	126	100	**481**	319
Sustaining capital [(2)]	**44**	52	48	**170**	128
Turnaround costs [(2)]	**–**	–	–	**79**	–
Capitalized interest, share-based compensation and other	**33**	(3)	28	**48**	96
Total Oil Sands Mining and Upgrading [(3)]	**227**	175	176	**778**	543
Horizon coker rebuild and collateral damage costs [(4)]	**15**	80	–	**404**	–
Midstream	**–**	1	3	**5**	7
Abandonments [(5)]	**66**	54	80	**213**	179
Head office	**2**	4	5	**18**	18
Total net capital expenditures	**$ 1,909**	$ 1,406	$ 1,945	**$ 6,414**	$ 5,514
By segment					
North America	**$ 1,546**	$ 1,045	$ 1,600	**$ 4,736**	$ 4,369
North Sea	**71**	46	38	**227**	149
Offshore Africa	**(18)**	1	43	**33**	249
Oil Sands Mining and Upgrading [(2)]	**242**	255	176	**1,182**	543
Midstream	**–**	1	3	**5**	7
Abandonments [(5)]	**66**	54	80	**213**	179
Head office	**2**	4	5	**18**	18
Total	**$ 1,909**	$ 1,406	$ 1,945	**$ 6,414**	$ 5,514

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

(2) Prior period figures have been reclassified to conform to the current period's presentation.

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

(4) The Company recognized $393 million of property damage insurance recoveries (see note 9 to the interim consolidated financial statements), offsetting the costs incurred related to the Coker rebuild and collateral damage costs.

(5) 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 year ended December 31, 2011 were $6,414 million compared to $5,514 million for the year ended December 31, 2010. Net capital expenditures for the fourth quarter of 2011 were $1,909 million compared to $1,945 million for the fourth quarter of 2010 and $1,406 million for the third quarter of 2011.

The increase in capital expenditures for the year ended December 31, 2011 from the comparable period in 2010 was primarily due to an increase in well drilling and completion expenditures related to the Company's record heavy crude oil drilling program, an increase in the Company's abandonment program and costs associated with the coker rebuild and collateral damage resulting from the coker fire, partially offset by lower property acquisitions.

The decrease in capital expenditures for the fourth quarter of 2011 from the comparable period in 2010 was due to lower exploration and evaluation expenditures and lower property acquisitions, partially offset by an increase in well drilling and completion expenditures related to the Company's record heavy crude oil drilling program and an increase in Horizon Phases 2/3 costs. The increase in capital expenditures for the fourth quarter of 2011 from the third quarter of 2011 was due to higher property acquisitions and an increase in well drilling and completion expenditures related to the Company's heavy oil drilling program, partially offset by lower costs associated with the coker rebuild and collateral damage.

Drilling Activity (number of wells)

	Three Months Ended			Year Ended	
	Dec 31 2011	Sep 30 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Net successful natural gas wells	**27**	21	18	**83**	92
Net successful crude oil wells (1)	**330**	317	318	**1,103**	934
Dry wells	**17**	10	8	**48**	33
Stratigraphic test / service wells	**112**	25	171	**657**	491
Total	**486**	373	515	**1,891**	1,550
Success rate (excluding stratigraphic test / service wells)	**95%**	97%	98%	**96%**	97%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 77% of the total capital expenditures for the year ended December 31, 2011 compared to approximately 83% for the year ended December 31, 2010.

During the fourth quarter of 2011, the Company targeted 29 net natural gas wells, including 2 wells in Northeast British Columbia, 24 wells in Northwest Alberta and 3 wells in the Northern Plains. The Company also targeted 345 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 218 primary heavy crude oil wells, 12 Pelican Lake heavy crude oil wells, 12 light crude oil wells and 50 bitumen (thermal oil) wells were drilled. Another 53 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall Primrose thermal production for the fourth quarter of 2011 averaged approximately 78,000 bbl/d, compared to approximately 104,000 bbl/d for the fourth quarter of 2010 and approximately 110,000 bbl/d for the third quarter of 2011. Lower fourth quarter 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.

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 second of seven pads and has commenced on the third pad.

Development of the tertiary recovery conversion projects at Pelican Lake continued in the fourth quarter of 2011. A total of 4 horizontal wells were drilled during the quarter. Pelican Lake production averaged approximately 40,000 bbl/d for the fourth quarter of 2011, compared to 38,000 bbl/d in the fourth quarter of 2010 and the third quarter of 2011.

For the first quarter of 2012, the Company's overall planned drilling activity in North America is expected to be 241 net crude oil wells and 13 net natural gas wells, excluding stratigraphic and service wells. As a result of lower 2012 natural gas prices than originally anticipated in the Company's 2012 budget, the Company will reduce its natural gas drilling to 45 wells and its natural gas capital estimate by approximately $170 million. This reduction in capital expenditures will reduce North America natural gas production by approximately 20 MMcf/d, which has been incorporated into the revised 2012 production guidance.

Oil Sands Mining and Upgrading

Phase 2/3 spending during the fourth quarter of 2011 continued to be focused on final construction and pre-commissioning of the third Ore Preparation Plant and associated hydro-transport as well as the additional product tankage, the butane treatment unit and the sulphur recovery unit. Final commissioning of the Ore Preparation Plant and associated hydro-transport was completed in January 2012.

Due to property damage resulting from a fire in the primary upgrading coking plant at January 6, 2011, the Company recognized a Horizon asset impairment provision of $396 million, net of accumulated depletion and amortization. Insurance proceeds of $393 million were also recognized, offsetting such property damage. Production resumed in August 2011.

During the fourth quarter of 2011, the Company finalized its property damage insurance claim with certain of its insurers. The Company believes that the remaining portion of the property damage insurance claim will be settled without any significant adjustments from the $393 million currently recognized. The Company also maintains business interruption insurance to reduce operating losses related to its ongoing Horizon operations. The Company finalized its business interruption insurance claim related to the fire for proceeds of $333 million.

Subsequent to December 31, 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. The Company has targeted mid to late March to return to full production levels. Cost estimates for the repair are not expected to be significant.

North Sea

During the fourth quarter of 2011, the Company incurred drilling and capital expenditures on the three Ninian platforms, facilities upgrade projects at Lyell and ongoing capital turnaround projects at Tiffany and Murchison.

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 and appropriate shut down procedures were activated. The vessel 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 Cote d'Ivoire. Preparations are ongoing and a rig has been contracted to commence drilling operations targeted for late 2012.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Dec 31 2011**		Sep 30 2011		Dec 31 2010
Working capital (deficit) (1)	**$**	**(894)**	$	(213)	$	(1,200)
Long-term debt (2) (3)	**$**	**8,571**	$	9,327	$	8,485
Share capital	**$**	**3,507**	$	3,431	$	3,147
Retained earnings		**19,365**		18,642		17,212
Accumulated other comprehensive loss		**26**		71		9
Shareholders' equity	**$**	**22,898**	$	22,144	$	20,368
Debt to book capitalization (3) (4)		**27%**		30%		29%
Debt to market capitalization (3) (5)		**17%**		22%		15%
After-tax return on average common shareholders' equity		**12%**		7%		8%
After-tax return on average capital employed		**10%**		6%		7%

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

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

(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.

At December 31, 2011, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations 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, 2010 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 on-going hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

During the fourth quarter of 2011, the Company filed base shelf prospectuses that allow for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2013. Subsequently, the Company issued US$1,000 million of unsecured notes under the US base shelf prospectus, comprised of US$500 million of 1.45% unsecured notes due November 2014 and US$500 million of 3.45% unsecured notes due November 2021. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the US$500 million of 3.45% unsecured notes due November 2021 at 3.96% and C$511 million. Proceeds from the securities issued were used to repay bank indebtedness under the Company's bank credit facilities. After issuing these securities, the Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus. If issued, these securities will bear interest as determined at the date of issuance.

During the third quarter of 2011, the Company repaid US$400 million of US dollar denominated debt securities bearing interest at 6.70%. During the second quarter of 2011, the $2,230 million revolving syndicated credit facility was increased to $3,000 million and extended to June 2015. The $1,500 million revolving syndicated credit facility is currently maturing in June 2012. 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. During the fourth quarter of 2010, the Company repaid $400 million of the medium-term notes bearing interest at 5.50%. At December 31, 2011, the Company had $3,795 million of available credit under its bank credit facilities.

Long-term debt was $8,571 million at December 31, 2011, resulting in a debt to book capitalization ratio of 27% (September 30, 2011- 30%; December 31, 2010 – 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 December 31, 2011 are discussed in note 7 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 March 6, 2012, in accordance with the policy, approximately 40% 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 December 31, 2011 are discussed in note 15 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at December 31, 2011, there were 1,096,460,000 common shares outstanding and 73,486,000 stock options outstanding. As at March 6, 2012, the Company had 1,100,567,000 common shares outstanding and 67,574,000 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 March 2011, an increase in the annual dividend paid by the Company to $0.36 per common share was approved for 2011. The increase represented a 20% increase from 2010.

On March 31, 2011, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), during the 12 month period commencing April 6, 2011 and ending April 5, 2012, up to 27,406,131 common shares or 2.5% of the common shares of the Company outstanding at March 25, 2011. As at December 31, 2011, 3,071,100 common shares had been purchased for cancellation at an average price of $33.68 per common share, for a total cost of $104 million.

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the TSX and NYSE during the 12 month period commencing April 6, 2010 and ending April 5, 2011, up to 27,163,940 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. A total of 2,000,000 common shares were purchased for cancellation under this Normal Course Issuer Bid at an average price of $33.77 per common share, for a total cost of $68 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 December 31, 2011, 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 December 31, 2011:

($ millions)	2012	2013	2014	2015	2016	Thereafter
Product transportation and pipeline	$ 247	$ 210	$ 199	$ 185	$ 123	$ 888
Offshore equipment operating leases	$ 118	$ 101	$ 100	$ 82	$ 53	$ 119
Long-term debt (1)	$ 356	$ 806	$ 865	$ 1,196	$ 255	$ 5,135
Interest and other financing costs (2)	$ 442	$ 403	$ 384	$ 339	$ 321	$ 4,116
Office leases	$ 30	$ 33	$ 34	$ 32	$ 33	$ 305
Other	$ 288	$ 158	$ 88	$ 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 December 31, 2011.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2010, the CICA Handbook was revised to incorporate IFRS and require publicly accountable enterprises to apply IFRS effective for years beginning on or after January 1, 2011. The 2011 fiscal year is the first year in which the Company has prepared its consolidated financial statements in accordance with IFRS as issued by the IASB.

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

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

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The Company is required to adopt IFRS 9, "Financial Instruments", effective January 1, 2015, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, "Financial Instruments - Recognition and Measurement". The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

In May 2011, the IASB issued the following new accounting standards, which are required to be adopted effective January 1, 2013:

- IFRS 10 "Consolidated Financial Statements" replaces IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee ("SIC") 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.
- IFRS 11 "Joint Arrangements" replaces IAS 31 "Interests in Joint Ventures" and SIC 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures, and prescribes the accounting treatment for each type of joint arrangement – recognition of the proportionate interest in the assets, liabilities, revenues and expenses; and equity accounting, respectively. There is no longer a choice of the accounting method.
- IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company's accounting for investments in other entities, but will impact the related disclosures.
- IFRS 13 "Fair Value Measurement" provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value.

In June 2011, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" that require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012.

In October 2011, the IASB issued IFRS Interpretation Committee ("IFRIC") 20 "Stripping Costs in the Production Phase of a Surface Mine". The IFRIC requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved. The IFRIC is effective for fiscal periods beginning on or after January 1, 2013.

The Company is currently assessing the impact of these new and amended standards on its consolidated financial statements. The Company does not plan to early adopt the above noted standards.

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.

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

Crude Oil and Natural Gas Reserves

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

Asset Retirement Obligations

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

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's average credit-adjusted risk-free interest rate, which is currently 4.6%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates and estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

Income Taxes

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

Risk Management Activities

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

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies 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 uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

Purchase Price Allocations

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

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

Share-based Compensation

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

Identification of Cash Generating Units ("CGUs")

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

Impairment of Assets

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

Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)	Note	**Dec 31 2011**	Dec 31 2010	Jan 1 2010
ASSETS				
Current assets				
Cash and cash equivalents		**$ 34**	$ 22	$ 13
Accounts receivable		**2,077**	1,481	1,148
Inventory		**550**	477	438
Prepaids and other		**120**	129	146
		2,781	2,109	1,745
Exploration and evaluation assets	4	**2,475**	2,402	2,293
Property, plant and equipment	5	**41,631**	38,429	37,018
Other long-term assets	6	**391**	14	6
		$ 47,278	$ 42,954	$ 41,062
LIABILITIES				
Current liabilities				
Accounts payable		**$ 526**	$ 274	$ 240
Accrued liabilities		**2,347**	1,735	1,430
Current income tax liabilities		**347**	430	94
Current portion of long-term debt	7	**359**	397	400
Current portion of other long-term liabilities	8	**455**	870	854
		4,034	3,706	3,018
Long-term debt	7	**8,212**	8,088	9,259
Other long-term liabilities	8	**3,913**	3,004	2,485
Deferred income tax liabilities		**8,221**	7,788	7,462
		24,380	22,586	22,224
SHAREHOLDERS' EQUITY				
Share capital	11	**3,507**	3,147	2,834
Retained earnings		**19,365**	17,212	15,927
Accumulated other comprehensive income	12	**26**	9	77
		22,898	20,368	18,838
		$ 47,278	$ 42,954	$ 41,062

Commitments and contingencies (note 16).

Approved by the Board of Directors on March 6, 2012

Consolidated Statements of Earnings (Loss)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Dec 31 2011	Three Months Ended Dec 31 2010	Year Ended Dec 31 2011	Year Ended Dec 31 2010
Product sales		**$ 4,788**	$ 3,787	**$ 15,507**	$ 14,322
Less: royalties		**(570)**	(431)	**(1,715)**	(1,421)
Revenue		**4,218**	3,356	**13,792**	12,901
Expenses					
Production		**1,034**	876	**3,671**	3,449
Transportation and blending		**582**	460	**2,327**	1,783
Depletion, depreciation and amortization	5	**998**	1,546	**3,604**	4,120
Administration		**47**	54	**235**	211
Share-based compensation	8	**207**	266	**(102)**	203
Asset retirement obligation accretion	8	**33**	31	**130**	123
Interest and other financing costs		**83**	120	**373**	448
Risk management activities	15	**78**	192	**(27)**	(134)
Foreign exchange (gain) loss		**(106)**	(110)	**1**	(163)
Horizon asset impairment provision	9	**–**	–	**396**	–
Insurance recovery – property damage	9	**3**	–	**(393)**	–
Insurance recovery – business interruption	9	**(16)**	–	**(333)**	–
		2,943	3,435	**9,882**	10,040
Earnings (loss) before taxes		**1,275**	(79)	**3,910**	2,861
Current income tax expense	10	**299**	176	**860**	789
Deferred income tax expense	10	**144**	54	**407**	399
Net earnings (loss)		**$ 832**	$ (309)	**$ 2,643**	$ 1,673
Net earnings (loss) per common share					
Basic	14	**$ 0.76**	$ (0.28)	**$ 2.41**	$ 1.54
Diluted	14	**$ 0.76**	$ (0.28)	**$ 2.40**	$ 1.53

Consolidated Statements of Comprehensive Income (Loss)

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2011	Three Months Ended Dec 31 2010	Year Ended Dec 31 2011	Year Ended Dec 31 2010
Net earnings (loss)	**$ 832**	$ (309)	**$ 2,643**	$ 1,673
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized loss during the period, net of taxes of $10 million (2010 – $8 million) – three months ended; $5 million (2010 – $13 million) – year ended	**(67)**	(63)	**(23)**	(40)
Reclassification to net earnings, net of taxes of $4 million (2010 – $nil million) – three months ended; $17 million (2010 – $1 million) – year ended	**11**	–	**52**	(4)
	(56)	(63)	**29**	(44)
Foreign currency translation adjustment				
Translation of net investment	**11**	(23)	**(12)**	(24)
Other comprehensive (loss) income, net of taxes	**(45)**	(86)	**17**	(68)
Comprehensive income (loss)	**$ 787**	$ (395)	**$ 2,660**	$ 1,605

Consolidated Statements of Changes in Equity

(millions of Canadian dollars, unaudited)	Note	Year Ended Dec 31 2011	Dec 31 2010
Share capital	11		
Balance – beginning of year		**$ 3,147**	$ 2,834
Issued upon exercise of stock options		**255**	170
Previously recognized liability on stock options exercised for common shares		**115**	149
Purchase of common shares under Normal Course Issuer Bid		**(10)**	(6)
Balance – end of year		**3,507**	3,147
Retained earnings			
Balance – beginning of year		**17,212**	15,927
Net earnings		**2,643**	1,673
Purchase of common shares under Normal Course Issuer Bid	11	**(94)**	(62)
Dividends on common shares	11	**(396)**	(326)
Balance – end of year		**19,365**	17,212
Accumulated other comprehensive income	12		
Balance – beginning of year		**9**	77
Other comprehensive income (loss), net of taxes		**17**	(68)
Balance – end of year		**26**	9
Shareholders' equity		**$ 22,898**	$ 20,368

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Dec 31 2011	Three Months Ended Dec 31 2010	Year Ended Dec 31 2011	Year Ended Dec 31 2010
Operating activities					
Net earnings (loss)		**$ 832**	$ (309)	**$ 2,643**	$ 1,673
Non-cash items					
Depletion, depreciation and amortization		**998**	1,546	**3,604**	4,120
Share-based compensation		**207**	266	**(102)**	203
Asset retirement obligation accretion		**33**	31	**130**	123
Unrealized risk management loss (gain)		**58**	180	**(128)**	(24)
Unrealized foreign exchange (gain) loss		**(117)**	(116)	**215**	(161)
Realized foreign exchange gain on repayment of US dollar debt securities		**–**	–	**(225)**	–
Deferred income tax expense		**144**	54	**407**	399
Horizon asset impairment provision	5, 9	**–**	–	**396**	–
Insurance recovery – property damage	9	**3**	–	**(393)**	–
Other		**(46)**	4	**(55)**	(8)
Abandonment expenditures		**(66)**	(80)	**(213)**	(179)
Net change in non-cash working capital		**267**	(39)	**(36)**	136
		2,313	1,537	**6,243**	6,282
Financing activities					
(Repayment) issue of bank credit facilities, net		**(1,632)**	622	**(647)**	(472)
Repayment of medium-term notes		**–**	(400)	**–**	(400)
Issue of US dollar debt securities, net		**1,011**	–	**621**	–
Issue of common shares on exercise of stock options		**63**	87	**255**	170
Purchase of common shares under Normal Course Issuer Bid		**(12)**	–	**(104)**	(68)
Dividends on common shares		**(99)**	(82)	**(378)**	(302)
Net change in non-cash working capital		**(5)**	(4)	**(15)**	(12)
		(674)	223	**(268)**	(1,084)
Investing activities					
Expenditures on exploration and evaluation assets and property, plant and equipment		**(1,843)**	(1,865)	**(6,201)**	(5,335)
Investment in other long-term assets		**25**	–	**(321)**	–
Net change in non-cash working capital		**195**	100	**559**	146
		(1,623)	(1,765)	**(5,963)**	(5,189)
Increase (decrease) in cash and cash equivalents		**16**	(5)	**12**	9
Cash and cash equivalents – beginning of period		**18**	27	**22**	13
Cash and cash equivalents – end of period		**$ 34**	$ 22	**$ 34**	$ 22
Interest paid		**$ 80**	$ 89	**$ 456**	$ 471
Income taxes paid		**$ 190**	$ 99	**$ 706**	$ 213

(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.

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

The accounting policies adopted by the Company under IFRS are set out below and are based on IFRS issued and outstanding as at December 31, 2011. Subject to certain transition elections disclosed in note 18, the Company has consistently applied the same accounting policies in its opening IFRS balance sheet at January 1, 2010 and throughout all periods presented, as if these policies had always been in effect.

Comparative information for 2010 has been restated from Canadian Generally Accepted Accounting Principles (“Canadian GAAP”) to comply with IFRS. In these consolidated financial statements, Canadian GAAP refers to Canadian GAAP before the adoption of IFRS. Note 18 discloses the impact of the transition to IFRS on the Company’s reported financial position, net earnings and cash flows, including the nature and effect of significant changes in accounting policies from those used in the Company’s Canadian GAAP consolidated financial statements for the year ended December 31, 2010. These interim consolidated financial statements should be read in conjunction with the Company’s 2010 annual consolidated financial statements, which were prepared in accordance with Canadian GAAP, and in consideration of the IFRS disclosures included in note 18 to these interim consolidated financial statements.

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost convention, unless otherwise required.

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships.

Certain of the Company’s activities are conducted through joint ventures. Where the Company has a direct ownership interest in jointly controlled assets, the revenue, expenses, assets and liabilities related to the jointly controlled assets are included in the consolidated financial statements in proportion to the Company’s interest. Where the Company has an interest in jointly controlled entities, it uses the equity method of accounting. Under the equity method, the Company’s investment is initially recognized at cost and subsequently adjusted for the Company’s share of the jointly controlled entity’s income or loss, less dividends received. Unrealized gains and losses on transactions between the Company and the jointly controlled entity are eliminated.

(B) CASH AND CASH EQUIVALENTS

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

(C) INVENTORY

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

(D) EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves.

E&E costs are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area. These costs are recognized immediately in net earnings.

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

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

(E) PROPERTY, PLANT AND EQUIPMENT

Exploration and Production

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

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

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

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

Oil Sands Mining and Upgrading

Capitalized costs for Oil Sands Mining and Upgrading are reported in a separate operating segment from the Company's North America Exploration and Production segment. Capitalized costs include property acquisition, construction and development costs, the estimate of any asset retirement costs, and applicable borrowing costs.

Mine-related costs and costs of the upgrader and related infrastructure located on the Horizon site are amortized on the unit-of-production method based on Horizon proved reserves or productive capacity, respectively. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 15 years.

Midstream and head office

The Company capitalizes all costs that expand the capacity or extend the useful life of the assets. Midstream assets are depreciated on a straight-line basis over their estimated useful lives ranging from 5 to 30 years. Head office assets are amortized on a declining balance basis.

Useful lives

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

Derecognition

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

Major maintenance expenditures

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

Impairment

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

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

(F) BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition.

(G) OVERBURDEN REMOVAL COSTS

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

(H) CAPITALIZED BORROWING COSTS

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

(I) LEASES

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

(J) ASSET RETIREMENT OBLIGATIONS

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

(K) FOREIGN CURRENCY TRANSLATION

(i) Functional and presentation currency

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

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

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

(ii) Transactions and balances

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

(L) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

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

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

(M) PRODUCTION SHARING CONTRACTS

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

(N) INCOME TAX

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

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

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

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date.

Income taxes are recognized in net earnings or other comprehensive income, consistent with the items to which they relate.

(O) SHARE-BASED COMPENSATION

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

(P) FINANCIAL INSTRUMENTS

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

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

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

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

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

Impairment of financial assets

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

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

(Q) RISK MANAGEMENT ACTIVITIES

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value as determined based on appropriate 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. The Company’s own credit risk is not included in the carrying amount of a risk management liability.

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

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

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

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

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

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

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

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

(R) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company’s net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses on the net investment in foreign operations that do not have a Canadian dollar functional currency. Other comprehensive income is shown net of related income taxes.

(S) PER COMMON SHARE AMOUNTS

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

(T) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are included in equity as a deduction, net of tax, from proceeds. When the Company acquires its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value is recognized as a reduction of retained earnings. Shares are cancelled upon purchase.

(U) DIVIDENDS

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

2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

The Company is required to adopt IFRS 9, "Financial Instruments", effective January 1, 2015, with earlier adoption permitted. IFRS 9 replaces existing requirements included in IAS 39, "Financial Instruments - Recognition and Measurement". The new standard replaces the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

In May 2011, the IASB issued the following new accounting standards, which are required to be adopted effective January 1, 2013:

- IFRS 10 "Consolidated Financial Statements" replaces IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee ("SIC") 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on how to apply the control principle to determine whether an investor controls an investee.
- IFRS 11 "Joint Arrangements" replaces IAS 31 "Interests in Joint Ventures" and SIC 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures, and prescribes the accounting treatment for each type of joint arrangement – recognition of the proportionate interest in the assets, liabilities, revenues and expenses; and equity accounting, respectively. There is no longer a choice of the accounting method.
- IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities. This standard does not impact the Company's accounting for investments in other entities, but will impact the related disclosures.
- IFRS 13 "Fair Value Measurement" provides guidance on how fair value should be applied where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value.

In June 2011, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" that require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. The standard is effective for fiscal years beginning on or after July 1, 2012.

In October 2011, the IASB issued IFRS Interpretation Committee ("IFRIC") 20 "Stripping Costs in the Production Phase of a Surface Mine". The IFRIC requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved. The IFRIC is effective for fiscal periods beginning on or after January 1, 2013.

The Company is currently assessing the impact of these new and amended standards on its consolidated financial statements. The Company does not plan to early adopt the above noted standards.

3. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

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

(a) Crude oil and natural gas reserves

Purchase price allocations, depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices.

(b) Asset retirement obligations

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

(c) Income taxes

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

(d) Fair value of derivatives and other financial instruments

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

(e) Purchase price allocations

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

(f) Share-based compensation

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

(g) Identification of CGUs

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

(h) Impairment of Assets

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

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	**North Sea**	**Offshore Africa**		
Cost					
At January 1, 2010	$ 2,102	$ –	$ 191	$ –	$ 2,293
Additions	563	6	3	–	572
Transfers to property, plant and equipment	(299)	–	(154)	–	(453)
Foreign exchange adjustments	–	(1)	(9)	–	(10)
At December 31, 2010	2,366	5	31	–	2,402
Additions	**309**	**1**	**2**	**–**	**312**
Transfers to property, plant and equipment	**(233)**	**(6)**	**–**	**–**	**(239)**
At December 31, 2011	**$ 2,442**	**$ –**	**$ 33**	**$ –**	**$ 2,475**

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At January 1, 2010	$ 36,159	$ 3,866	$ 2,666	$ 13,758	$ 284	$ 214	$ 56,947
Additions	4,403	190	254	411	7	18	5,283
Transfers from E&E assets	299	–	154	–	–	–	453
Disposals/ derecognitions	–	(5)	–	–	–	(11)	(16)
Foreign exchange adjustments and other	–	(238)	(146)	–	–	(5)	(389)
At December 31, 2010	40,861	3,813	2,928	14,169	291	216	62,278
Additions	**5,026**	**235**	**76**	**1,545**	**7**	**18**	**6,907**
Transfers from E&E assets	**233**	**6**	**–**	**–**	**–**	**–**	**239**
Disposals/ derecognitions [1]	**–**	**–**	**(29)**	**(503)**	**–**	**–**	**(532)**
Foreign exchange adjustments and other	**–**	**93**	**69**	**–**	**–**	**–**	**162**
At December 31, 2011	**$ 46,120**	**$ 4,147**	**$ 3,044**	**$ 15,211**	**$ 298**	**$ 234**	**$ 69,054**
Accumulated depletion and depreciation							
At January 1, 2010	$ 16,427	$ 2,054	$ 1,008	$ 207	$ 81	$ 152	$ 19,929
Expense	2,473	295	298	396	8	13	3,483
Impairment [2]	–	–	637	–	–	–	637
Disposals/ derecognitions	–	(5)	–	–	–	(11)	(16)
Foreign exchange adjustments and other	(5)	(139)	(39)	4	–	(5)	(184)
At December 31, 2010	18,895	2,205	1,904	607	89	149	23,849
Expense	**2,826**	**248**	**242**	**266**	**7**	**15**	**3,604**
Impairment [1]	**–**	**–**	**–**	**396**	**–**	**–**	**396**
Disposals/ derecognitions [1]	**–**	**–**	**(29)**	**(503)**	**–**	**–**	**(532)**
Foreign exchange adjustments and other	**–**	**59**	**35**	**10**	**–**	**2**	**106**
At December 31, 2011	**$ 21,721**	**$ 2,512**	**$ 2,152**	**$ 776**	**$ 96**	**$ 166**	**$ 27,423**
Net book value							
- at December 31, 2011	**$ 24,399**	**$ 1,635**	**$ 892**	**$ 14,435**	**$ 202**	**$ 68**	**$ 41,631**
- at December 31, 2010	$ 21,966	$ 1,608	$ 1,024	$ 13,562	$ 202	$ 67	$ 38,429
- at January 1, 2010	$ 19,732	$ 1,812	$ 1,658	$ 13,551	$ 203	$ 62	$ 37,018

(1) During 2011, the Company derecognized certain property, plant and equipment related to the coker fire at Horizon in the amount of $411 million based on estimated replacement cost, net of accumulated depletion and depreciation of $15 million. There was a resulting impairment charge of $396 million. For additional information, refer to note 9.

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

Development projects not subject to depletion

At December 31, 2011	$	1,443
At December 31, 2010	$	934
At January 1, 2010	$	1,270

The Company acquired a number of producing crude oil and natural gas assets in the North American Exploration and Production segment for total cash consideration of $1,012 million during the year ended December 31, 2011 (year ended December 31, 2010 – $1,482 million), net of associated asset retirement obligations of $79 million (year ended December 31, 2010 – $22 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 year ended December 31, 2011, pre-tax interest of $59 million was capitalized to property, plant and equipment (December 31, 2010 – $28 million) using a capitalization rate of 4.7% (December 31, 2010 – 4.9%).

6. OTHER LONG-TERM ASSETS

	Dec 31 2011	Dec 31 2010	Jan 1 2010
Investment in North West Redwater Partnership	**$ 321**	$ –	$ –
Other	**70**	14	6
	$ 391	$ 14	$ 6

Other long-term assets include a $321 million investment in the 50% owned North West Redwater Partnership ("Redwater"), which 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.

7. LONG-TERM DEBT

	Dec 31 2011	Dec 31 2010	Jan 1 2010
Canadian dollar denominated debt			
Bank credit facilities	**$ 796**	$ 1,436	$ 1,897
Medium-term notes	**800**	800	1,200
	1,596	2,236	3,097
US dollar denominated debt			
US dollar debt securities (December 31, 2011-US$6,900 million; December 31, 2010 and January 1, 2010-US$6,300 million)	**7,017**	6,266	6,594
Less: original issue discount on US dollar debt securities (1)	**(21)**	(20)	(22)
	6,996	6,246	6,572
Fair value impact of interest rate swaps on US dollar debt securities (2)	**31**	47	39
	7,027	6,293	6,611
Long-term debt before transaction costs	**8,623**	8,529	9,708
Less: transaction costs (1) (3)	**(52)**	(44)	(49)
	8,571	8,485	9,659
Less: current portion (1) (2)	**359**	397	400
	$ 8,212	$ 8,088	$ 9,259

(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 $31 million (December 2010 – $47 million, January 2010 – $39 million) to reflect the fair value impact of hedge accounting.

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

Bank Credit Facilities

As at December 31, 2011, 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.

During the second quarter of 2011, the $2,230 million revolving syndicated credit facility was increased to $3,000 million and extended to June 2015. 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 and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

The Company's weighted average interest rate on bank credit facilities outstanding as at December 31, 2011, was 2.2% (December 31, 2010 – 1.5%), and on long-term debt outstanding for the year ended December 31, 2011 was 4.7% (December 31, 2010 – 4.9%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $436 million, including $127 million related to Horizon and $174 million related to North Sea operations, were outstanding at December 31, 2011.

Medium-Term Notes

During November 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

During the third quarter of 2011, the Company repaid US$400 million of US dollar debt securities bearing interest at 6.70%.

During November 2011, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until November 2013. Subsequently, the Company issued US$1,000 million of unsecured notes under the US base shelf prospectus, comprised of US$500 million of 1.45% unsecured notes due November 2014 and US$500 million of 3.45% unsecured notes due November 2021. Concurrently, the Company entered into cross currency swaps to fix the Canadian dollar interest and principal repayment amounts on the US$500 million of 3.45% unsecured notes due November 2021 at 3.96% and C$511 million (note 15). Proceeds from the securities issued were used to repay bank indebtedness. After issuing these securities, the Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

8. OTHER LONG-TERM LIABILITIES

	Dec 31 2011	Dec 31 2010	Jan 1 2010
Asset retirement obligations	**$ 3,577**	$ 2,624	$ 2,214
Share-based compensation	**432**	663	622
Risk management (note 15)	**274**	485	325
Other	**85**	102	178
	4,368	3,874	3,339
Less: current portion	**455**	870	854
	$ 3,913	$ 3,004	$ 2,485

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, 2010 – 5.1%; January 1, 2010 – 5.8%). A reconciliation of the discounted asset retirement obligations is as follows:

	Dec 31 2011	Dec 31 2010
Balance – beginning of year	**$ 2,624**	$ 2,214
Liabilities incurred	**12**	12
Liabilities acquired	**79**	22
Liabilities settled	**(213)**	(179)
Asset retirement obligation accretion	**130**	123
Revision of estimates	**924**	474
Foreign exchange	**21**	(42)
Balance – end of year	**$ 3,577**	$ 2,624

Share-based compensation

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

	Dec 31 2011	Dec 31 2010
Balance – beginning of year	**$ 663**	$ 622
Share-based compensation (recovery) expense	**(102)**	203
Cash payment for options surrendered	**(14)**	(45)
Transferred to common shares	**(115)**	(149)
Capitalized to Oil Sands Mining and Upgrading	**–**	32
Balance – end of year	**432**	663
Less: current portion	**384**	623
	$ 48	$ 40

9. HORIZON ASSET IMPAIRMENT PROVISION AND INSURANCE RECOVERY

During the first quarter of 2011, the Company recognized an asset impairment provision in the Oilsands 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. Estimated insurance proceeds receivable of $396 million were also recognized, offsetting the property damage. During the third quarter of 2011, final mechanical, testing and commissioning activities were completed, and production resumed.

During the fourth quarter of 2011, the Company finalized the costs to restore plant operating activities, with no revision to the original asset impairment provision. The Company also finalized its property damage insurance claim with certain of its insurers, reducing its insurance recovery by $3 million to $393 million. The Company believes that the remaining portion of the property damage insurance recovery claim will be settled without further adjustment.

The Company also maintains business interruption insurance to reduce operating losses related to its ongoing Horizon operations. During the fourth quarter of 2011, the Company finalized its business interruption insurance claim for $333 million, resulting in the recognition of an additional insurance recovery of $16 million.

10. INCOME TAXES

The provision for income tax is as follows:

	Three Months Ended		Year Ended	
	Dec 31 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Current corporate income tax – North America	**$ 119**	$ 49	**$ 315**	$ 431
Current corporate income tax – North Sea	**84**	84	**245**	203
Current corporate income tax – Offshore Africa	**50**	23	**140**	64
Current PRT[(1)] expense – North Sea	**39**	14	**135**	68
Other taxes	**7**	6	**25**	23
Current income tax expense	**299**	176	**860**	789
Deferred corporate income tax expense	**157**	65	**412**	408
Deferred PRT expense – North Sea	**(13)**	(11)	**(5)**	(9)
Deferred income tax expense	**144**	54	**407**	399
Income tax expense	**$ 443**	$ 230	**$ 1,267**	$ 1,188

(1) Petroleum Revenue Tax

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

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.

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.

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

11. 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.

	Year ended Dec 31, 2011	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of year	**1,090,848**	**$ 3,147**
Issued upon exercise of stock options	**8,683**	**255**
Previously recognized liability on stock options exercised for common shares	**–**	**115**
Purchase of common shares under Normal Course Issuer Bid	**(3,071)**	**(10)**
Balance – end of year	**1,096,460**	**$ 3,507**

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

In 2011, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the twelve month period commencing April 6, 2011 and ending April 5, 2012, up to 27,406,131 common shares or 2.5% of the common shares of the Company outstanding at March 25, 2011. As at December 31, 2011, the Company purchased 3,071,100 common shares at an average price of $33.68 per common share, for a total cost of $104 million. Retained earnings was reduced by $94 million, representing the excess of the purchase price of the common shares over their average carrying value.

Stock Options

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

	Year ended Dec 31, 2011		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of year	**66,844**	**$**	**33.31**
Granted	**19,516**	**$**	**37.54**
Surrendered for cash settlement	**(1,124)**	**$**	**29.84**
Exercised for common shares	**(8,683)**	**$**	**29.34**
Forfeited	**(3,067)**	**$**	**35.87**
Outstanding – end of year	**73,486**	**$**	**34.85**
Exercisable – end of year	**26,486**	**$**	**32.13**

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.

12. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		Dec 31 2011		Dec 31 2010
Derivative financial instruments designated as cash flow hedges	**$**	**62**	$	33
Foreign currency translation adjustment		**(36)**		(24)
	$	**26**	$	9

During the next twelve months, $6 million is expected to be reclassified to net earnings from accumulated other comprehensive income, reducing net earnings.

13. 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 December 31, 2011, the ratio was below the target range at 27%.

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.

	Dec 31 2011	Dec 31 2010	Jan 1 2010
Long-term debt [(1)]	**$ 8,571**	$ 8,485	$ 9,659
Total shareholders' equity	**$ 22,898**	$ 20,368	$ 18,838
Debt to book capitalization	**27%**	29%	34%

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

14. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Weighted average common shares outstanding – basic (thousands of shares)	**1,095,072**	1,088,993	**1,095,582**	1,088,096
Effect of dilutive stock options (thousands of shares)	**4,390**	8,996	**7,000**	7,552
Weighted average common shares outstanding – diluted (thousands of shares)	**1,099,462**	1,097,989	**1,102,582**	1,095,648
Net earnings (loss)	**$ 832**	$ (309)	**$ 2,643**	$ 1,673
Net earnings (loss) per common share – basic	**$ 0.76**	$ (0.28)	**$ 2.41**	$ 1.54
– diluted	**$ 0.76**	$ (0.28)	**$ 2.40**	$ 1.53

15. FINANCIAL INSTRUMENTS

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

	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)**

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

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

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

The carrying 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:

	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]	**(7,775)**	**(9,120)**	**–**
	$ (8,049)	**$ (9,120)**	**$ (274)**

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

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

(1) Excludes financial assets and liabilities where 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 $31 million (December 31, 2010 – $47 million, January 1, 2010 – $39 million) to reflect the fair value impact of hedge accounting.

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

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

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

Asset (liability)	Dec 31, 2011	Dec 31, 2010	Jan 1, 2010
Derivatives held for trading			
Crude oil price collars	**$ (13)**	$ (64)	$ (256)
Crude oil put options	**–**	(83)	–
Natural gas price collars	**–**	–	72
Interest rate swaps	**–**	–	11
Foreign currency forward contracts	**(25)**	(20)	(9)
Cash flow hedges			
Natural gas swaps	**–**	(49)	–
Cross currency swaps	**(236)**	(269)	(158)
Fair value hedges			
Interest rate swaps	**–**	–	15
	$ (274)	$ (485)	$ (325)
Included within:			
Current portion of other long-term liabilities	**$ (43)**	$ (222)	$ (182)
Other long-term liabilities	**(231)**	(263)	(143)
	$ (274)	$ (485)	$ (325)

Ineffectiveness arising from cash flow hedges recognized in the consolidated statements of earnings for the year ended December 31, 2011 resulted in a loss of $2 million (December 31, 2010 – loss of $1 million).

Risk Management

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

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies 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:

	Year Ended Dec 31, 2011	Year Ended Dec 31, 2010
Asset (liability)		
Balance – beginning of year	**$ (485)**	$ (325)
Net cost of outstanding put options	**–**	106
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**128**	24
Interest expense	**–**	30
Foreign exchange	**42**	(101)
Other comprehensive income	**41**	(58)
Settlement of interest rate swaps and other	**–**	(55)
	(274)	(379)
Add: put premium financing obligations (1)	**–**	(106)
Balance – end of year	**(274)**	(485)
Less: current portion	**(43)**	(222)
	$ (231)	$ (263)

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

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

	Three Months Ended		Year Ended	
	Dec 31 2011	Dec 31 2010	**Dec 31 2011**	Dec 31 2010
Net realized risk management loss (gain)	**$ 20**	$ 12	**$ 101**	$ (110)
Net unrealized risk management loss (gain)	**58**	180	**(128)**	(24)
	$ 78	$ 192	**$ (27)**	$ (134)

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 December 31, 2011, 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 (1)								
Crude oil price collars (2)	Jan 2012	–	Dec 2012	50,000 bbl/d	US$80.00	–	US$134.87	Brent

(1) Subsequent to December 31, 2011, the Company entered into 50,000 bbl/d of US$80 WTI put options for the month of February for a total cost of US$3 million and 100,000 bbl/d of US$80 WTI put options for the period March to December 2012 for a total cost of US$62 million.

(2) Subsequent to December 31, 2011, the Company entered into an additional 50,000 bbl/d of US$80-US$136.06 Brent collars for the period February to December 2012.

During the fourth quarter of 2011, US$27 million of put option costs were settled.

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. During the fourth quarter of 2011, the Company unwound C$200 million of 1.4475% interest rate swaps with an original maturity of February 2012 for nominal consideration. At December 31, 2011, 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 December 31, 2011, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Jan 2012	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2012	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2012	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2012	–	Mar 2038	US$550	1.170	6.25%	5.76%

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

In addition to the cross currency swap contracts noted above, at December 31, 2011, the Company had US$2,043 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 December 31, 2011, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2011, the Company had net risk management assets of $nil with specific counterparties related to derivative financial instruments (December 31, 2010 – $nil, January 1, 2010 – $7 million).

c) Liquidity Risk

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

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

The maturity dates for financial liabilities are as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	526	$	–	$	–	$	–
Accrued liabilities	$	2,347	$	–	$	–	$	–
Risk management	$	43	$	40	$	120	$	71
Other long-term liabilities	$	28	$	13	$	34	$	–
Long-term debt (1)	$	356	$	806	$	2,316	$	5,135

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

16. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2012	2013	2014	2015	2016	Thereafter
Product transportation and pipeline	$ 247	$ 210	$ 199	$ 185	$ 123	$ 888
Offshore equipment operating leases	$ 118	$ 101	$ 100	$ 82	$ 53	$ 119
Office leases	$ 30	$ 33	$ 34	$ 32	$ 33	$ 305
Other	$ 288	$ 158	$ 88	$ 24	$ 2	$ 8

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

17. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	Exploration and Production — North America: Three months ended Dec 31		Year ended Dec 31		North Sea: Three months ended Dec 31		Year ended Dec 31		Offshore Africa: Three months ended Dec 31		Year ended Dec 31		Total Exploration and Production: Three months ended Dec 31		Year ended Dec 31	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Segmented product sales	**3,163**	2,516	**11,806**	9,713	**317**	303	**1,224**	1,058	**308**	261	**946**	884	**3,788**	3,080	**13,976**	11,655
Less: royalties	**(482)**	(385)	**(1,538)**	(1,267)	**(1)**	(1)	**(3)**	(2)	**(46)**	(22)	**(114)**	(62)	**(529)**	(408)	**(1,655)**	(1,331)
Segmented revenue	**2,681**	2,131	**10,268**	8,446	**316**	302	**1,221**	1,056	**262**	239	**832**	822	**3,259**	2,672	**12,321**	10,324
Segmented expenses																
Production	**516**	416	**1,933**	1,675	**103**	107	**412**	387	**66**	46	**186**	167	**685**	569	**2,531**	2,229
Transportation and blending	**575**	456	**2,301**	1,761	**3**	1	**13**	8	**–**	–	**1**	1	**578**	457	**2,315**	1,770
Depletion, depreciation and amortization	**726**	609	**2,840**	2,435	**65**	77	**249**	297	**72**	754	**242**	984	**863**	1,440	**3,331**	3,716
Asset retirement obligation accretion	**17**	13	**70**	52	**9**	9	**33**	36	**2**	2	**7**	7	**28**	24	**110**	95
Realized risk management activities	**20**	12	**101**	(110)	**–**	–	**–**	–	**–**	–	**–**	–	**20**	12	**101**	(110)
Horizon asset impairment provision	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Insurance recovery – property damage (note 9)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Insurance recovery - business interruption (note 9)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**1,854**	1,506	**7,245**	5,813	**180**	194	**707**	728	**140**	802	**436**	1,159	**2,174**	2,502	**8,388**	7,700
Segmented earnings (loss) before the following	**827**	625	**3,023**	2,633	**136**	108	**514**	328	**122**	(563)	**396**	(337)	**1,085**	170	**3,933**	2,624
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing costs																
Unrealized risk management activities																
Foreign exchange (gain) loss																
Total non-segmented expenses																
Earnings (loss) before taxes																
Current income tax expense																
Deferred income tax expense																
Net earnings (loss)																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter-segment elimination and other				Total			
	Three months ended Dec 31		Year ended Dec 31		Three months ended Dec 31		Year ended Dec 31		Three months ended Dec 31		Year ended Dec 31		Three months ended Dec 31		Year ended Dec 31	
	2011	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Segmented product sales	**1,005**	700	**1,521**	2,649	**22**	20	**88**	79	**(27)**	(13)	**(78)**	(61)	**4,788**	3,787	**15,507**	14,322
Less: royalties	**(41)**	(23)	**(60)**	(90)	**–**	–	**–**	–	**–**	–	**–**	–	**(570)**	(431)	**(1,715)**	(1,421)
Segmented revenue	**964**	677	**1,461**	2,559	**22**	20	**88**	79	**(27)**	(13)	**(78)**	(61)	**4,218**	3,356	**13,792**	12,901
Segmented expenses																
Production	**344**	304	**1,127**	1,208	**7**	6	**26**	22	**(2)**	(3)	**(13)**	(10)	**1,034**	876	**3,671**	3,449
Transportation and blending	**16**	15	**62**	61	**–**	–	**–**	–	**(12)**	(12)	**(50)**	(48)	**582**	460	**2,327**	1,783
Depletion, depreciation and amortization	**133**	104	**266**	396	**2**	2	**7**	8	**–**	–	**–**	–	**998**	1,546	**3,604**	4,120
Asset retirement obligation accretion	**5**	7	**20**	28	**–**	–	**–**	–	**–**	–	**–**	–	**33**	31	**130**	123
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**20**	12	**101**	(110)
Horizon asset impairment provision	**–**	–	**396**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**396**	–
Insurance recovery – property damage (note 9)	**3**	–	**(393)**	–	**–**	–	**–**	–	**–**	–	**–**	–	**3**	–	**(393)**	–
Insurance recovery – business interruption (note 9)	**(16)**	–	**(333)**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(16)**	–	**(333)**	–
Total segmented expenses	**485**	430	**1,145**	1,693	**9**	8	**33**	30	**(14)**	(15)	**(63)**	(58)	**2,654**	2,925	**9,503**	9,365
Segmented earnings (loss) before the following	**479**	247	**316**	866	**13**	12	**55**	49	**(13)**	2	**(15)**	(3)	**1,564**	431	**4,289**	3,536
Non-segmented expenses																
Administration													**47**	54	**235**	211
Share-based compensation													**207**	266	**(102)**	203
Interest and other financing costs													**83**	120	**373**	448
Unrealized risk management activities													**58**	180	**(128)**	(24)
Foreign exchange (gain) loss													**(106)**	(110)	**1**	(163)
Total non-segmented expenses													**289**	510	**379**	675
Earnings (loss) before taxes													**1,275**	(79)	**3,910**	2,861
Current income tax expense													**299**	176	**860**	789
Deferred income tax expense													**144**	54	**407**	399
Net earnings (loss)													**832**	(309)	**2,643**	1,673

Capital Expenditures [1]

	Year Ended					
	Dec 31, 2011			Dec 31, 2010		
	Net expenditures	**Non cash and fair value changes[2]**	**Capitalized costs**	Net expenditures	Non cash and fair value changes[2]	Capitalized costs
Exploration and evaluation						
Exploration and Production						
North America	**$ 309**	**$ (233)**	**$ 76**	$ 563	$ (299)	$ 264
North Sea	**1**	**(6)**	**(5)**	6	–	6
Offshore Africa	**2**	**–**	**2**	3	(154)	(151)
	$ 312	**$ (239)**	**$ 73**	$ 572	$ (453)	$ 119
Property, plant and equipment						
Exploration and Production						
North America	**$ 4,427**	**$ 832**	**$ 5,259**	$ 3,806	$ 896	$ 4,702
North Sea	**226**	**15**	**241**	143	42	185
Offshore Africa	**31**	**16**	**47**	246	162	408
	4,684	**863**	**5,547**	4,195	1,100	5,295
Oil Sands Mining and Upgrading[3][4]	**1,182**	**(140)**	**1,042**	543	(132)	411
Midstream	**5**	**2**	**7**	7	–	7
Head office	**18**	**–**	**18**	18	(11)	7
	$ 5,889	**$ 725**	**$ 6,614**	$ 4,763	$ 957	$ 5,720

(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, share-based compensation, and the impact of intersegment eliminations.

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

Segmented Assets

	Total Assets	
	Dec 31 2011	Dec 31 2010
Exploration and Production		
North America	**$ 28,554**	$ 25,486
North Sea	**1,809**	1,759
Offshore Africa	**1,070**	1,263
Other	**23**	15
Oil Sands Mining and Upgrading	**15,433**	14,026
Midstream	**321**	338
Head office	**68**	67
	$ 47,278	$ 42,954

18. TRANSITION TO IFRS

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

(i) Transition elections

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

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

(ii) Transition adjustments

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

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

Reconciliations of the Consolidated Balance Sheets

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

Reconciliations of the Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)		Year ended Dec 31, 2010			Three months ended Dec 31, 2010		
		Canadian GAAP	**Adj**	**IFRS**	**Canadian GAAP**	**Adj**	**IFRS**
	Note	**$**	**$**	**$**	**$**	**$**	**$**
Product sales		14,322	–	14,322	3,787	–	3,787
Less: royalties		(1,421)	–	(1,421)	(431)	–	(431)
Revenue		12,901	–	12,901	3,356	–	3,356
Expenses							
Production	(a)	3,447	2	3,449	874	2	876
Transportation and blending		1,783	–	1,783	460	–	460
Depletion, depreciation and amortization	(a)(e)(l)	4,036	84	4,120	1,578	(32)	1,546
Administration	(a)	210	1	211	53	1	54
Share-based compensation	(c)	294	(91)	203	336	(70)	266
Asset retirement obligation accretion	(e)	107	16	123	27	4	31
Interest and other financing costs	(h)	449	(1)	448	120	–	120
Risk management activities	(h)	(121)	(13)	(134)	199	(7)	192
Foreign exchange gain	(j)	(182)	19	(163)	(114)	4	(110)
		10,023	17	10,040	3,533	(98)	3,435
Earnings (loss) before taxes		2,878	(17)	2,861	(177)	98	(79)
Taxes other than income tax		119	(119)	–	25	(25)	–
Current income tax expense		698	91	789	156	20	176
Deferred income tax expense	(i) (j)	364	35	399	58	(4)	54
Net earnings (loss)		1,697	(24)	1,673	(416)	107	(309)
Net earnings (loss) per common share							
Basic		1.56	(0.02)	1.54	(0.38)	0.10	(0.28)
Diluted		1.56	(0.03)	1.53	(0.38)	0.10	(0.28)

Reconciliations of the Consolidated Statements of Comprehensive Income (Loss)

(millions of Canadian dollars, unaudited)		Year ended Dec 31, 2010			Three months ended Dec 31, 2010		
	Note	Canadian GAAP $	Adj $	IFRS $	Canadian GAAP $	Adj $	IFRS $
Net earnings (loss)		1,697	(24)	1,673	(416)	107	(309)
Net change in derivative financial instruments designated as cash flow hedges							
Unrealized loss during the period	(h)	(35)	(18)	(53)	(52)	(19)	(71)
Income tax		11	2	13	6	2	8
Unrealized loss during the period, net of tax		(24)	(16)	(40)	(46)	(17)	(63)
Reclassification to net earnings		(5)	–	(5)	–	–	–
Income tax		1	–	1	–	–	–
Reclassification to net earnings, net of taxes		(4)	–	(4)	–	–	–
		(28)	(16)	(44)	(46)	(17)	(63)
Foreign currency translation adjustment							
Translation of net investment		(35)	11	(24)	(24)	1	(23)
Other comprehensive loss, net of taxes		(63)	(5)	(68)	(70)	(16)	(86)
Comprehensive income (loss)		1,634	(29)	1,605	(486)	91	(395)

Notes:

(a) Deemed cost of property, plant and equipment

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

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

(b) Leases

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

(c) Share-based compensation

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

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

(d) Borrowing costs

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

(e) Asset retirement obligations

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

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

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

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

(f) Cumulative translation adjustment

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

(g) Business combinations

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

(h) Risk management

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

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

(i) Petroleum Revenue Tax

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

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

(j) UK deferred income tax liabilities

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

For the year ended December 31, 2010, net earnings decreased by $19 million.

(k) Reclassification of current portion of deferred income tax

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

(l) Horizon major maintenance costs

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

For the year ended December 31, 2010, net earnings decreased by $19 million, net of taxes of $6 million, to reflect the impact of higher depletion charges.

(m) Long-term debt

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

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

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

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

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

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

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

Adjustments to the statements of cash flows

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

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated October 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 December 31, 2011:

Interest coverage (times)	
Net earnings [(1)]	9.6x
Cash flow from operations [(2)]	17.6x

(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 Time, 11:00 a.m. Eastern Time on Thursday, March 8, 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, March 15, 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 6410782.

WEBCAST

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

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