Canadian Natural

Press Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2012 FOURTH QUARTER AND YEAR END RESULTS

CALGARY, ALBERTA – MARCH 7, 2013 – FOR IMMEDIATE RELEASE

Commenting on fourth quarter and year end results, Canadian Natural's Vice-Chairman, John Langille stated, "Canadian Natural generated in 2012 over $6.0 billion of annual cash flow from operations and demonstrated capital discipline throughout the year. The Company's exhibited long term ability to maintain flexibility of capital allocation and financial discipline over different commodity price cycles has helped us weather challenging conditions and capitalize when opportunities arise. Prudent management of our balance sheet resulted in year-end debt to book capitalization of 26% and year-end debt to EBITDA of 1.2 times.

As part of the Company's long term goal to return funds to its shareholders, throughout 2012, the Company purchased for cancellation under its Normal Course Issuer Bid over eleven million common shares at an average price of $28.91. For 2013, the Board has approved a 19% dividend increase to C$0.125 per quarter, C$0.50 per share annualized. This will be the thirteenth consecutive year that the Company has announced an increased annual dividend distribution representing a compound annual growth rate of 21% over the period. In addition, the Company's Board of Directors have directed Management to continue with an active program, subject to market conditions, to purchase for cancellation common shares under the Company's Normal Course Issuer Bid at or above the levels of shares purchased in financial year 2012. Our share purchase program and dividend increases, along with the defined resource development of our diverse asset base, and our debt management and opportunistic acquisitions demonstrate our balanced approach to our long standing effective strategy. Canadian Natural is strong and stable, and well positioned to deliver shareholder value in the near, mid and long term."

Steve Laut, President of Canadian Natural concluded, "During 2012, the Company made very good progress in our transition to a longer life, low decline asset base. We continued to balance development of our large resource base by focusing on high return assets and our ability to deliver timely results. In 2012 we made significant progress towards continued execution on the creation of shareholder value. We achieved 9% overall production growth in 2012 from 2011. At Horizon, substantial improvements have been made in operating discipline and our enhanced concentration on safe, steady and reliable operations has led to greater plant reliability. At Kirby, construction progress has been solid and we are 81% complete and on budget. We had another solid year of adding new reserves. Our barrel of oil equivalent reserves on a Company Gross proved plus probable basis increased by 5% to 7.9 billion barrels, replacing 246% of our 2012 production.

For 2013 and beyond, we will continue to focus on operating efficiencies and discipline and will allocate capital to projects that provide the greatest value and highest returns to our shareholders. This will allow the Company over time to generate strong and growing free cash flow."

QUARTERLY AND ANNUAL HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended Dec 31 2012	Sep 30 2012	Dec 31 2011	Year Ended Dec 31 2012	Dec 31 2011
Net earnings	**$ 352**	$ 360	$ 832	**$ 1,892**	$ 2,643
Per common share – basic	**$ 0.32**	$ 0.33	$ 0.76	**$ 1.72**	$ 2.41
– diluted	**$ 0.32**	$ 0.33	$ 0.76	**$ 1.72**	$ 2.40
Adjusted net earnings from operations (1)	**$ 359**	$ 353	$ 972	**$ 1,618**	$ 2,540
Per common share – basic	**$ 0.33**	$ 0.33	$ 0.89	**$ 1.48**	$ 2.32
– diluted	**$ 0.33**	$ 0.32	$ 0.88	**$ 1.47**	$ 2.30
Cash flow from operations (2)	**$ 1,548**	$ 1,431	$ 2,158	**$ 6,013**	$ 6,547
Per common share – basic	**$ 1.41**	$ 1.31	$ 1.97	**$ 5.48**	$ 5.98
– diluted	**$ 1.41**	$ 1.30	$ 1.96	**$ 5.47**	$ 5.94
Capital expenditures, net of dispositions	**$ 1,767**	$ 1,621	$ 1,909	**$ 6,308**	$ 6,414
Daily production, before royalties					
Natural gas (MMcf/d)	**1,134**	1,191	1,280	**1,220**	1,257
Crude oil and NGLs (bbl/d)	**469,964**	469,168	444,286	**451,378**	389,053
Equivalent production (BOE/d) (3)	**658,973**	667,616	657,599	**654,665**	598,526

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

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

(3) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") 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

- Total crude oil and NGLs production was 469,964 bbl/d for Q4/12. Q4/12 crude oil production volumes increased 6% from Q4/11 as a result of a strong thermal in situ production cycle and successful primary heavy and light crude oil drilling programs.
- Total natural gas production for Q4/12 was 1,134 MMcf/d. Q4/12 natural gas production volumes decreased 11% and 5%, as expected, from Q4/11 and Q3/12 respectively. The decrease in production was primarily due to expected production declines and shut in production volumes as a result of the Company's strategic decision to allocate capital to higher return crude oil projects.
- Canadian Natural generated quarterly cash flow from operations of $1.55 billion compared with $2.16 billion in Q4/11 and $1.43 billion in Q3/12. The decrease in cash flow from Q4/11 was due to lower average realized product prices, lower natural gas sales volumes, and lower synthetic crude oil ("SCO") sales volumes. These factors were partially offset by higher crude oil sales volumes in North America. The increase in cash flow from Q3/12 was primarily related to higher North America crude oil and NGLs sales volumes.
- Adjusted net earnings from operations for Q4/12 was $359 million, compared to adjusted net earnings of $972 million in Q4/11 and $353 million in Q3/12. Changes in adjusted net earnings reflect the changes in cash flow from operations.

Annual

- Total overall production for the year averaged 654,665 BOE/d representing an increase of 9% from 2011. Canadian Natural's production volume growth was driven by successful light and heavy crude oil drilling programs and greater reliability of Horizon Oil Sands ("Horizon") operations.
- Total crude oil and NGLs production for the year averaged 451,378 bbl/d, an increase of 16% from 2011. The Company's strategic allocation of capital to crude oil projects resulted in a 22% annual increase in primary heavy crude oil production volumes, a 13% annual increase of North America light crude oil and NGLs production and a 113% annual increase in Horizon production.
- As expected, total natural gas production for the year averaged 1,220 MMcf/d, a decrease of 3% from 2011 levels. The decrease in production was due to expected production declines, shut in production volumes and a reduced drilling program, reflecting Canadian Natural's strategic decision to allocate capital to higher return crude oil projects.
- Cash flow from operations was approximately $6.0 billion in 2012 compared to approximately $6.5 billion in 2011. The decrease in cash flow was primarily due to lower realized crude oil and NGLs prices, lower realized natural gas prices and lower realized SCO prices. These factors were partially offset by higher crude oil and SCO production volumes in North America.
- Adjusted net earnings from operations in 2012 decreased to $1.6 billion compared to $2.5 billion in 2011. Changes in adjusted net earnings reflect the changes in cash flow from operations and higher depletion, depreciation and amortization ("DD&A") expense.
- 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 Gross reserves using forecast prices and costs as at December 31, 2012:
    - Company Gross proved crude oil, SCO, bitumen and NGL reserves increased 6% to 4.33 billion barrels. Company Gross proved natural gas reserves decreased 7% to 4.14 Tcf. On a BOE basis total proved reserves increased 4% to 5.02 billion BOE.
    - Company Gross proved plus probable crude oil, SCO, bitumen and NGL reserves increased 6% to 6.92 billion barrels. Company Gross proved plus probable natural gas reserves decreased 5% to 5.79 Tcf. On a BOE basis total proved plus probable reserves increased 5% to 7.89 billion BOE.
    - Company Gross proved reserve additions, including acquisitions, were 404 million barrels of crude oil, SCO, bitumen and NGL and 135 billion cubic feet of natural gas for 426 million BOE. The total proved reserve replacement ratio was 178%. The total proved reserve life index is 22.8 years.
    - Company Gross proved plus probable reserve additions, including acquisitions, were 565 million barrels of crude oil, bitumen, SCO and NGL and 132 billion cubic feet of natural gas for 587 million BOE. The total proved plus probable reserve replacement ratio was 246%. The total proved plus probable reserve life index is 35.8 years.
    - Proved undeveloped crude oil, SCO, bitumen and NGL reserves accounted for 31% of the corporate total proved reserves and proved undeveloped natural gas reserves accounted for 4% of the corporate total proved reserves.
    - Of the reserve additions by the Company in 2012, 95% of Company Gross proved reserve additions and 96% of Company Gross proved plus probable reserve additions were crude oil, SCO, bitumen and NGLs.
- Total net exploration and production reserve replacement expenditures totaled approximately $4,444 million in 2012, including acquisitions and excluding Horizon. Horizon project capital (including capitalized interest, share-based compensation and other) totaled approximately $1,366 million and sustaining and turnaround capital totaled approximately $244 million.

Operational and Financial

- North America Exploration and Production crude oil and NGLs production for the year averaged 326,829 bbl/d representing an increase of 11% from 2011 levels.
    - Canadian Natural's primary heavy crude oil continued to provide strong netbacks and the highest return on capital in the Company's portfolio of diverse and balanced assets. Primary heavy crude oil operations achieved Q4/12 production volumes of over 130,000 bbl/d, resulting in the eighth consecutive quarter of record production which contributed to 22% average annual production growth over 2011. Primary heavy crude oil production volumes are targeted to increase by a further 13% in 2013.

- Completion of another successful light crude oil drilling program of 124 net wells, Enhanced Oil Recovery ("EOR") activities and acquisitions resulted in 13% annual growth of North America light crude oil and NGLs production volumes over 2011 levels. North America light crude oil and NGLs production volumes in 2013 are targeted to increase by 6%.
- Pelican Lake reservoir performance throughout 2012 was very positive. In Q4/12, production averaged approximately 36,400 bbl/d as volumes at Pelican Lake were restricted due to temporary produced polymer treatment and facility constraints. In addition, production volumes from the primary heavy oil area of Woodenhouse were also restricted as they utilize Pelican Lake processing facilities. Construction completion of a new battery targeted in June 2013 will correct the temporary treatment constraints and enable a step increase in Pelican Lake and Woodenhouse production volumes through the second half of 2013. Annual production guidance for Pelican Lake remains unchanged and is targeted to range from 46,000 bbl/d to 50,000 bbl/d.
- Thermal in situ production ramped up during 2012 as pads re-entered the production cycle. Q4/12 volumes averaged 121,000 bbl/d, a 19% increase over Q3/12 volumes. 2012 annual thermal production averaged approximately 99,500 bbl/d and is targeted to grow by 5% in 2013.
- In 2012, Canadian Natural acquired an additional 12,630 net hectares of leases at its Kirby Thermal Oil Sands Project ("Kirby Project"), which are being incorporated into the Company's robust portfolio of thermal in situ projects. The Company's thermal projects are targeted to add 40,000 bbl/d of production every two to three years that is targeted to ultimately grow to approximately 500,000 bbl/d of capacity, from current production capacity of 130,000 bbl/d. The Company Gross proved plus probable long-life, low-decline bitumen reserves from thermal in situ oil sands increased by 23%, to 2,122 million barrels in 2012 and total Company Gross proved bitumen reserves increased by 9%, to 1,066 million barrels in 2012.
- Kirby South Phase 1, the Company's first large scale steam assisted gravity drainage ("SAGD") project, is targeted for first steam in Q4/13 and is targeted to add 40,000 bbl/d of production in late 2014. Construction is progressing slightly ahead of schedule and on budget.

▪ Horizon SCO production volumes averaged approximately 86,000 bbl/d in 2012. The Company continues its enhanced focus on operational discipline and safe, steady and reliable operations at Horizon. Reliability of the Horizon plant continues to steadily improve and annual SCO production is targeted to range from 100,000 bbl/d to 108,000 bbl/d in 2013, which includes the impact of the planned May 2013 turnaround.

- The addition of the third ore preparation plant ("OPP") and associated hydro-transport unit was integrated into the Company's mining operations in early 2012. The equipment has substantially increased the overall reliability at Horizon.
- In January and February 2013, strong performance from Horizon resulted in average SCO volumes of approximately 113,000 bbl/d and 107,000 bbl/d, respectively. Q1/13 production guidance is targeted to range from 105,000 bbl/d to 111,000 bbl/d of SCO.
- Canadian Natural maintains a flexible schedule for Horizon expansion construction to ensure capital efficiencies. The staged expansion to 250,000 bbl/d of SCO production capacity at Horizon continues to be broken down into smaller more focused projects which has kept projects currently under construction trending at or below cost estimates. In 2012, long life, low decline SCO Company Gross proved reserves increased 6% to 2.26 billion barrels. SCO Company Gross proved plus probable reserves remained essentially unchanged at 3.35 billion barrels.

▪ During Q4/12, the Redwater Partnership 50,000 bbl/d bitumen refinery (78,000 bbl/d of bitumen blend) was sanctioned by its owners (50% Canadian Natural). The Company will provide 12,500 bbl/d of bitumen feedstock to the refinery as a toll payer. Work continues on the Redwater project and completion is targeted for mid-2016.

▪ During 2012, Canadian Natural purchased 11,012,700 common shares for cancellation at a weighted average price of $28.91 per common share.

▪ For 2013, the Board has approved a 19% dividend increase to C$0.125 per quarter, C$0.50 per share annualized. This will be the thirteenth consecutive year that the Company has announced an increased annual dividend distribution representing a compound annual growth rate of 21% over the period.

▪ In addition, the Company's Board of Directors have directed Management to continue with an active program, subject to market conditions, to purchase for cancellation common shares under the Company's Normal Course Issuer Bid at or above the levels of shares purchased in financial year 2012.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in core regions where it can own a substantial land base and associated infrastructure. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning and operating associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Further, the Company maintains large project inventories and production diversification among each of the commodities it produces; light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen and 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, 2012 (thousands of net acres)[(1)]	**Drilling activity year ended Dec 31, 2012 (net wells)[(2)]**
North America		
Northeast British Columbia	**2,954**	**20.6**
Northwest Alberta	**2,196**	**51.9**
Northern Plains	**6,603**	**984.8**
Southern Plains	**1,026**	**43.8**
Southeast Saskatchewan	**100**	**37.0**
Thermal In Situ Oil Sands	**837**	**556.0**
	13,716	**1,694.1**
Oil Sands Mining and Upgrading	**59**	**303.0**
North Sea	**128**	**0.9**
Offshore Africa	**4,307**	**–**
	18,210	**1,998.0**

(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			
	2012		2011	
	Gross	**Net**	Gross	Net
Crude oil	**1,255**	**1,203**	1,159	1,103
Natural gas	**42**	**35**	102	83
Dry	**34**	**33**	49	48
Subtotal	**1,331**	**1,271**	1,310	1,234
Stratigraphic test / service wells	**728**	**727**	659	657
Total	**2,059**	**1,998**	1,969	1,891
Success rate (excluding stratigraphic test / service wells)		**97%**		96%

North America Exploration and Production

North America crude oil and NGLs

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Crude oil and NGLs production (bbl/d)	**351,983**	332,895	291,839	**326,829**	295,618
Net wells targeting crude oil	**313**	371	345	**1,236**	1,147
Net successful wells drilled	**294**	365	330	**1,203**	1,103
Success rate	**94%**	98%	96%	**97%**	96%

- North America crude oil and NGLs production for the year averaged 326,829 bbl/d representing an increase of 11% from 2011. The increase in average yearly production was largely a result of successful drilling programs in primary heavy and light crude oil.
- North America crude oil and NGLs production for Q4/12 was 351,983 bbl/d. Q4/12 crude oil and NGLs production volumes increased 21% and 6% from Q4/11 and Q3/12 levels, respectively. The increase in production from Q4/11 was driven by higher primary heavy crude oil and thermal production volumes.
- Primary heavy crude oil operations achieved record quarterly production in Q4/12 of approximately 130,200 bbl/d which contributed to 22% average annual production growth over 2011 levels. Canadian Natural executed a record drilling program of 886 net primary heavy crude oil wells in 2012.
- During 2012 the reservoir performance at Pelican Lake demonstrated expected positive results.
  - Strong operating efficiencies were achieved at Pelican Lake as operating costs decreased to an annual average of $11.89/bbl in 2012.
  - In Q4/12, reservoir performance remained strong with incremental production response from the polymer flood. As production increased to facility capacity, the ability to treat the polymer produced was constrained. As a result, oil production at both Pelican Lake and Woodenhouse was curtailed.
  - Construction of the new battery, targeted for completion in June 2013, will address these temporary treatment constraints and enable a step increase in production volumes at both Pelican Lake and Woodenhouse. 2013 production expected for Pelican Lake remains unchanged and is targeted to range from 46,000 bbl/d to 50,000 bbl/d.
- North America light crude oil and NGLs annual production increased 13% in 2012 over 2011 levels as a result of a successful drilling program consisting of 124 net light crude oil wells. In 2013, Canadian Natural targets to drill 114 net light crude oil wells, 41 of which are targeting new play developments that were initiated in 2012. The Company continues to advance horizontal multi-frac well technology in pools across its land base. In addition, 70% of targeted total drilling will be focused on horizontal wells.
- Canadian Natural's robust portfolio of thermal in situ projects is a significant part of the Company's defined plan to transition to a longer-life, more sustainable asset base with the ability to generate significant shareholder value for decades to come. The Company targets to grow thermal in situ production to approximately 500,000 bbl/d of capacity by delivering projects that will add 40,000 bbl/d of production every two to three years.
  - At Primrose, total thermal operating costs including energy costs for Q4/12 were $7.95/bbl. Annual thermal operating costs including energy costs were $9.69/bbl. Thermal production averaged over 120,000 bbl/d in Q4/12, representing a 19% increase from Q3/12 to Q4/12, primarily due to new pads at Primrose East entering their production cycles. Production volumes are targeted to increase by 5% in 2013.
  - Kirby South Phase 1 is slightly ahead of plan and on budget. All major equipment and modules have been delivered and installed on site with overall construction progress ahead of schedule. An update to the project at the end of Q4/12 is as follows:
    - Overall project is 81% complete.
    - Overall construction is 73% complete.
    - Drilling and Completions are 82% complete. Drilling on the fifth of seven pads was completed in Q4/12. In early 2013 the sixth pad was drilled and the seventh pad is currently being drilled.

    - First steam-in is targeted for Q4/13 and production is targeted to ramp up to 40,000 bbl/d in late 2014.
  - On Kirby North Phase 1, detailed engineering is now in progress. Construction of the main access road has been completed and site preparation continues. A stratigraphic (“strat”) drilling program consisting of 50 wells is targeted for Q1/13. First steam-in is targeted for 2016. Full project sanction is expected in Q3/13.
- Planned drilling activity for 2013 includes 132 net thermal in situ wells and 1,022 net crude oil wells, excluding strat test and service wells.
- Canadian Natural has an active strat test well drilling program to delineate the reservoir characteristics for future projects. The Company targets to drill 463 strat wells in 2013.

North America natural gas

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Natural gas production (MMcf/d)	**1,113**	1,169	1,255	**1,198**	1,231
Net wells targeting natural gas	**3**	9	29	**35**	86
Net successful wells drilled	**3**	9	27	**35**	83
Success rate	**100%**	100%	93%	**100%**	97%

- North America natural gas production for the year averaged 1,198 MMcf/d representing a decrease of 3% from 2011 levels. During Q4/12, natural gas production averaged 1,113 MMcf/d representing a decrease of 11% from Q4/11 and 5% from Q3/12. The decrease in production levels was primarily due to expected production declines reflecting Canadian Natural’s strategic decision to allocate capital to higher return crude oil projects. As well, the Company shut in a cumulative total of 40 MMcf/d of natural gas volumes as a result of weakened natural gas pricing. In Q4/12, production was restricted after ending fixed processing agreements for certain natural gas volumes to maintain flexible cost control in response to weakening gas pricing.
- During 2012, due to weak natural gas pricing, Canadian Natural reduced its capital expenditures related to natural gas. As a result, drilling and expansion at Septimus, the Company's liquids rich Montney play, was deferred into 2013, with the anticipation of improved pricing. To date, the expansion is on track and is targeted for completion in late 2013 which will increase targeted natural gas sales levels from Septimus to 125 MMcf/d, yielding 12,200 bbl/d of liquids following processing through the plant and deep cut facilities.
- Canadian Natural is the second largest producer of natural gas in Canada and a significant owner and operator of natural gas infrastructure in Western Canada. The North America Company Gross proved plus probable natural gas reserve base of 5.57 Tcf generates operating free cash flow and presents significant upside potential for natural gas production and value when natural gas prices recover.
- Canadian Natural has a dominant Montney land position with over one million high quality net acres, the largest in the industry. In order to maximize the value of this important asset Canadian Natural has begun the process to monetize approximately 250,000 net acres (approximately 390 net sections) of our Montney land base in the liquids rich fairway in the Graham Kobes area of North East British Columbia. Under the process Canadian Natural will consider either an outright sale of the lands or a joint venture partner with LNG expertise to jointly develop the lands. If this process meets our internal targets and a transaction is completed, Canadian Natural will continue to have one of the largest undeveloped Montney land bases in Canada with lands contained in the two major areas of Septimus, British Columbia and North West Alberta.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Crude oil production (bbl/d)					
North Sea	**19,140**	19,502	26,769	**19,824**	29,992
Offshore Africa	**15,762**	17,566	22,726	**18,648**	23,009
Natural gas production (MMcf/d)					
North Sea	**1**	2	6	**2**	7
Offshore Africa	**20**	20	19	**20**	19
Net wells targeting crude oil	–	–	–	–	0.9
Net successful wells drilled	–	–	–	–	–
Success rate	–	–	–	–	0%

- Canadian Natural's international assets provide light crude oil balance to the Company's diverse portfolio and generated over $200 million of free cash flow in 2012.
- International crude oil production averaged 38,472 bbl/d during 2012 which was within the Company's previously stated guidance of 38,000 bbl/d – 39,000 bbl/d for the year. Production volumes declined from 2011 as a result of the suspension of production at Banff/Kyle (North Sea) due to storm damage in Q4/11, maintenance activities on a third-party operated pipeline in the North Sea, natural field declines, and planned maintenance activities at Ninian (North Sea), Baobab and Espoir (Offshore Africa).
- International light oil activities in 2013 will include a ramp up of drilling operations in the North Sea, the commencement of abandonment operations at Murchison in the North Sea, and commencement of the infill drilling program at Espoir, Offshore Africa.
- The Company continues with the partnering process for South Africa. Targeted drilling windows are from Q4/13 to Q1/14 and from Q4/14 to Q1/15.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Synthetic crude oil production (bbl/d)	**83,079**	99,205	102,952	**86,077**	40,434

- Horizon Oil Sands achieved average annual SCO production of 86,077 bbl/d in 2012. Production volumes were 113% higher than 2011 volumes as the reliability of the Horizon plant steadily improved in 2012.
- Average SCO production of 83,079 bbl/d was achieved at Horizon during Q4/12. Production decreased 16% from Q3/12 as a result of the previously announced 12 day planned proactive maintenance activities completed in October. In late December, additional unplanned maintenance activities were performed on the OPPs which contributed to lower quarterly volumes.
- In January and February 2013, strong performance from Horizon resulted in average SCO volumes of approximately 113,000 bbl/d and 107,000 bbl/d, respectively. Q1/13 production guidance is targeted to range from 105,000 bbl/d to 111,000 bbl/d of SCO.
- The first major turnaround at Horizon is planned for May 2013. To ensure effective execution of the turnaround and to ensure greater reliability, the turnaround has been increased from 18 days to 24 days. 2013 annual guidance has not been affected and remains unchanged at 100,000 bbl/d to 108,000 bbl/d of SCO.
- Canadian Natural's staged expansion to 250,000 bbl/d of SCO production capacity continues to progress on track. An update to the expansion at the end of Q4/12 is as follows:
  - Overall Horizon expansion is 18% complete.

- Reliability – Tranche 2 is 86% complete. This project is targeted for completion in 2013; an additional 5,000 bbl/d of production capacity will be added at completion.
- Directive 74 includes technological investment and research into tailings management. This portion remains on track and is currently 16% complete.
- Phase 2A is the coker expansion. The expansion is 47% complete, and is targeted to add 10,000 bbl/d of production capacity in 2015.
- Phase 2B is 8% complete. This phase includes lump sum contracts for major components such as gas/oil hydrotreatment, froth treatment and a hydrogen plant. This phase is targeted to add another 45,000 bbl/d of production capacity in 2016.
- Phase 3 is on track and engineering is underway. This phase is 8% complete, and includes the addition of supplementary extraction trains. This phase is targeted to increase production capacity by 80,000 bbl/d in 2017.
- Projects currently under construction are trending at or below cost estimates.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 88.20**	$ 92.19	$ 94.02	**$ 94.19**	$ 95.14
WCS blend differential from WTI (%) (2)	**21%**	24%	11%	**22%**	18%
SCO price (US$/bbl)	**$ 91.90**	$ 90.84	$ 102.95	**$ 92.59**	$ 103.63
Average realized pricing before risk management (C$/bbl) (3)	**$ 64.23**	$ 67.59	$ 85.28	**$ 70.24**	$ 77.46
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.89**	$ 2.08	$ 3.29	**$ 2.28**	$ 3.48
Average realized pricing before risk management (C$/Mcf) (3)	**$ 3.16**	$ 2.28	$ 3.50	**$ 2.44**	$ 3.73

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Average crude oil and NGLs pricing excludes SCO. Pricing is net of transportation and blending costs, excluding risk management activities.

- The WCS heavy crude oil differential ("WCS differential") as a percent of WTI averaged 22% during 2012 compared with 18% in 2011. During Q4/12 the WCS differential averaged 21%, in line with the Company's long term expectations. The Company anticipates continued volatility in the differential for the first half of 2013 and narrowing of the differential thereafter as additional heavy oil conversion and pipeline capacity come on stream.
- During October and November 2012, the WCS differential averaged 11% and 16% respectively, widening out to 34% in December 2012 as a result of unplanned pipeline capacity limitations and refinery-planned lower crude oil inventories at year-end. During January and February 2013, the WCS differential widened to average 37% but was partially offset by higher overall WTI pricing. For March 2013, the WCS differential has narrowed to average 29%.
- Canadian Natural contributed 157,000 bbl/d of its heavy crude oil stream to the WCS blend in 2012. The Company remains the largest contributor to the WCS blend, accounting for 53%.
- During 2012, Canadian natural gas production declined in response to lower pricing while US natural gas production remained steady throughout the year. Natural gas pricing recovered to AECO $2.89 in Q4/12 but benchmark pricing will continue to remain volatile until the demand from the power generation sector increases enough to offset strong North American supply.

NORTH WEST REDWATER UPGRADING AND REFINING

During Q4/12, the Redwater Partnership 50,000 bbl/d bitumen refinery (78,000 bbl/d of bitumen blend) was sanctioned by its owners (50% Canadian Natural). Work continues on the North West Redwater refinery and completion is targeted for mid-2016. The Company will also provide 12,500 bbl/d of bitumen feedstock to the refinery as a toll payer. There is potential to further expand the downstream capacity of the North West Redwater refinery from its 50,000 bbl/d of bitumen facility capacity in Phase 1 to 150,000 bbl/d of bitumen facility capacity.

The North West Redwater refinery asset strengthens the Company's position by providing a competitive return on investment and by adding 50,000 bbl/d of bitumen conversion capacity in Alberta which will help reduce volatility in pricing all Western Canadian heavy crude oil.

FINANCIAL REVIEW

The Company continues to implement proven strategies and focuses on disciplined capital allocation. As a result, the financial position of Canadian Natural remains strong. Canadian Natural's cash flow generation, credit facilities, 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 near, mid and long term.

- The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production of 658,973 BOE/d for Q4/12 with over 97% of production located in G8 countries.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 26.0% and debt to EBITDA of 1.2x. At December 31, 2012, long-term debt amounted to $8.7 billion compared with $8.6 billion at December 31, 2011.
- Canadian Natural maintains significant financial stability and liquidity represented by approximately $3.66 billion in available unused bank lines at the end of the 2012.
- The Company's commodity hedging program protects investment returns, ensures ongoing balance sheet strength and supports the Company's cash flow for its capital expenditures programs. Through the use of collars, the Company has hedged 48% of its forecasted 2013 crude oil volumes; 200,000 bbl/d of crude oil volumes in Q1/13, and 250,000 bbl/d of crude oil volumes in Q2/13, Q3/13 and Q4/13. Details of the Company's commodity hedging program can be found on the Company's website at www.cnrl.com.
- During 2012, Canadian Natural purchased 11,012,700 common shares for cancellation at a weighted average price of $28.91 per common share.
- For 2013, the Board has approved a 19% dividend increase to C$0.125 per quarter, C$0.50 per share annualized. This will be the thirteenth consecutive year that the Company has announced an increased annual dividend distribution representing a compound annual growth rate of 21% over the period.
- In addition, the Company's Board of Directors have directed Management to continue with an active program, subject to market conditions, to purchase for cancellation common shares under the Company's Normal Course Issuer Bid at or above the levels of shares purchased in financial year 2012.

OUTLOOK

The Company forecasts 2013 production levels before royalties to average between 1,085 and 1,145 MMcf/d of natural gas and between 482,000 and 513,000 bbl/d of crude oil and NGLs. Q1/13 production guidance before royalties is forecast to average between 1,130 and 1,150 MMcf/d of natural gas and between 471,000 and 495,000 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.

CORPORATE ANNOUNCEMENTS

Board of Directors Changes

James S. Palmer has informed the Company of his decision after 16 years of continuous service as a Director, to not stand for re-election to the Board of Directors at the Annual and Special Meeting of Shareholder on May 2, 2013. During Mr. Palmer's tenure with the Company, Canadian Natural has transitioned from a conventional oil and natural gas player based in western Canada to one of the largest independent crude oil and natural gas producers in the world with both domestic and international operations. Canadian Natural and the Board would like to thank Mr. Palmer for his valued wisdom, insight, guidance, leadership and dedication to the Company and its shareholders since his appointment as a director in 1997.

Management Changes

John G. Langille, Vice-Chairman, has announced his decision to retire from Canadian Natural effective May 2, 2013 immediately following the Annual and Special Meeting of Shareholders. John has served Canadian Natural for 37 years in various roles, most recently in the capacity of Vice-Chairman and prior to that as President. Through John's untiring efforts and guidance, Canadian Natural has remained focused on our defined growth plan thereby creating value for our shareholders through targeting cost effective alternatives to developing our portfolio of projects and to being one of the most effective and efficient producers in our industry. Canadian Natural and the Board would like to thank John for his dedicated service and loyalty to the Company.

As part of the Canadian Natural's management stewardship, high priority is assigned to succession planning to ensure the continued strength of the Company's leadership team.

Tim S. McKay, currently Chief Operating Officer, will become Executive Vice-President and Chief Operating Officer. He will continue to be responsible for the Canadian Conventional and International operations, and in addition will now be responsible for Horizon operations.

Douglas A. Proll, currently Chief Financial Officer and Senior Vice-President, Finance will become Executive Vice-President. He will continue to be a senior member of the Company's Management Committee and will have direct responsibility for certain non-financial departments and provide additional leadership in Investor Relations and other areas of stakeholder relations.

Corey B. Bieber, Vice-President Finance and Investor Relations will assume the role of Chief Financial Officer and Senior Vice-President, Finance. Corey joined Canadian Natural in 2001 and has been responsible for Treasury and Investor Relations since then and became a member of the Company's Management Committee in 2009. In his new role, Corey will be responsible for all aspects of the finance functions at Canadian Natural.

The appointments of Mr. McKay, Mr. Bieber and Mr. Proll are effective March 28, 2013.

YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2012 the Company retained Independent Qualified Reserves Evaluators (“Evaluators”), Sproule Associates Limited, Sproule International Limited (together as “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 6% to 4.33 billion barrels. Company Gross proved natural gas reserves decreased 7% to 4.14 Tcf. Total proved reserves increased 4% to 5.02 billion BOE.
- Company Gross proved plus probable crude oil, SCO, bitumen and NGL reserves increased 6% to 6.92 billion barrels. Company Gross proved plus probable natural gas reserves decreased 5% to 5.79 Tcf. Total proved plus probable reserves increased 5% to 7.89 billion BOE.
- Company Gross proved reserve additions, including acquisitions, were 404 million barrels of crude oil, SCO, bitumen and NGL and 135 billion cubic feet of natural gas for 426 million BOE. The total proved reserve replacement ratio was 178%. The total proved reserve life index is 22.8 years.
- Company Gross proved plus probable reserve additions, including acquisitions, were 565 million barrels of crude oil, bitumen, SCO and NGL and 132 billion cubic feet of natural gas for 587 million BOE. The total proved plus probable reserve replacement ratio was 246%. The total proved plus probable reserve life index is 35.8 years.
- Proved undeveloped crude oil, SCO, bitumen and NGL reserves accounted for 31% 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 7% to 1.74 billion barrels. Company Gross proved natural gas reserves decreased 7% to 3.99 Tcf. Total proved BOE increased 3% to 2.41 billion barrels.
- North America Company Gross proved plus probable crude oil, bitumen and NGL reserves increased 16% to 3.08 billion barrels. Company Gross proved plus probable natural gas reserves decreased 5% to 5.57 Tcf. Total proved plus probable BOE increased 11% to 4.01 billion barrels.
- North America Company Gross proved reserve additions and revisions, including acquisitions, were 230 million barrels of crude oil, bitumen and NGL and 157 billion cubic feet of natural gas for 256 million BOE. The total proved reserve replacement ratio is 133%. The total proved reserve life index in 14.3 years.
- North America Company Gross proved plus probable reserve additions and revisions, including acquisitions, were 548 million barrels of crude oil, bitumen and NGL and 174 billion cubic feet of natural gas for 577 million BOE. The total proved plus probable reserve replacement ratio was 299%. The total proved plus probable reserve life index is 23.8 years.
- Proved undeveloped crude oil, bitumen and NGL reserves accounted for 38% of the North America total proved reserves and proved undeveloped natural gas reserves accounted for 8% of the North America total proved reserves.
- Thermal oil Company Gross proved reserves increased 9% to 1,066 million barrels primarily due to category transfers from probable undeveloped to proved undeveloped at Kirby North and new proved undeveloped additions at Primrose and Wolf Lake. Proved bitumen reserve additions and revisions were 128 million barrels. Total proved plus probable bitumen reserves increased 23% to 2,122 million barrels primarily due to proved plus probable undeveloped additions at Primrose and Wolf Lake and probable undeveloped additions at Grouse.
- Company Gross proved plus probable bitumen reserves additions and revisions were 432 million barrels.

North America Oil Sands Mining and Upgrading

- Company Gross proved synthetic crude oil reserves increased 6% to 2.26 billion barrels.
- Proved reserve additions were 167 million barrels primarily due to additional stratigraphic wells drilled in the north pit.

International Exploration and Production

- North Sea Company Gross proved reserves decreased 2% to 240 million BOE primarily due to production. North Sea Company Gross proved plus probable reserves are 349 million BOE.
- Offshore Africa Company Gross proved reserves decreased 7% to 115 million BOE primarily due to production. Offshore Africa Company Gross proved plus probable reserves are 177 million BOE.

Summary of Company Gross Crude Oil, Bitumen, Natural Gas & NGL Reserves

As of December 31, 2012
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	92	85	217	238	1,837	2,664	53	2,966
Developed Non-Producing	2	23	11	104	–	213	3	178
Undeveloped	19	96	39	724	418	1,108	38	1,519
Total Proved	113	204	267	1,066	2,255	3,985	94	4,663
Probable	51	80	105	1,056	1,096	1,589	44	2,697
Total Proved plus Probable	164	284	372	2,122	3,351	5,574	138	7,360
North Sea								
Proved								
Developed Producing	49					3		49
Developed Non-Producing	14					55		23
Undeveloped	164					24		168
Total Proved	227					82		240
Probable	105					20		109
Total Proved plus Probable	332					102		349
Offshore Africa								
Proved								
Developed Producing	65					56		75
Developed Non-Producing	–					–		–
Undeveloped	38					13		40
Total Proved	103					69		115
Probable	55					42		62
Total Proved plus Probable	158					111		177
Total Company								
Proved								
Developed Producing	206	85	217	238	1,837	2,723	53	3,090
Developed Non-Producing	16	23	11	104	–	268	3	201
Undeveloped	221	96	39	724	418	1,145	38	1,727
Total Proved	443	204	267	1,066	2,255	4,136	94	5,018
Probable	211	80	105	1,056	1,096	1,651	44	2,868
Total Proved plus Probable	654	284	372	2,122	3,351	5,787	138	7,886

Summary of Company Net Crude Oil, Bitumen, Natural Gas & NGL Reserves
As of December 31, 2012
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	81	71	170	179	1,516	2,394	37	2,453
Developed Non-Producing	1	19	10	83	–	178	2	145
Undeveloped	16	82	32	564	375	968	30	1,260
Total Proved	98	172	212	826	1,891	3,540	69	3,858
Probable	42	64	75	801	835	1,367	34	2,079
Total Proved plus Probable	140	236	287	1,627	2,726	4,907	103	5,937
North Sea								
Proved								
Developed Producing	49					3		49
Developed Non-Producing	14					55		23
Undeveloped	164					24		168
Total Proved	227					82		240
Probable	105					20		109
Total Proved plus Probable	332					102		349
Offshore Africa								
Proved								
Developed Producing	55					39		61
Developed Non-Producing	–					–		–
Undeveloped	30					9		32
Total Proved	85					48		93
Probable	42					28		47
Total Proved plus Probable	127					76		140
Total Company								
Proved								
Developed Producing	185	71	170	179	1,516	2,436	37	2,563
Developed Non-Producing	15	19	10	83	–	233	2	168
Undeveloped	210	82	32	564	375	1,001	30	1,460
Total Proved	410	172	212	826	1,891	3,670	69	4,191
Probable	189	64	75	801	835	1,415	34	2,235
Total Proved plus Probable	599	236	287	1,627	2,726	5,085	103	6,426

Reconciliation of Company Gross Reserves by Product
As of December 31, 2012
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, 2011	114	175	276	974	2,119	4,266	95	4,464
Discoveries	–	–	–	–	–	6	–	1
Extensions	4	24	1	68	–	52	2	107
Infill Drilling	5	20	–	10	–	16	1	39
Improved Recovery	–	–	5	–	–	–	–	5
Acquisitions	1	–	–	–	–	43	1	9
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	–	–	–	–	14	(38)	(1)	7
Technical Revisions	4	31	(1)	50	153	79	5	255
Production	(15)	(46)	(14)	(36)	(31)	(438)	(9)	(224)
December 31, 2012	113	204	267	1,066	2,255	3,985	94	4,663

North Sea	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, 2011	228					98		244
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	4					1		4
Technical Revisions	2					(16)		(1)
Production	(7)					(1)		(7)
December 31, 2012	227					82		240

Offshore Africa	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, 2011	109					83		123
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	1					–		1
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	–					(7)		(1)
Production	(7)					(7)		(8)
December 31, 2012	103					69		115

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, 2011	451	175	276	974	2,119	4,447	95	4,831
Discoveries	–	–	–	–	–	6	–	1
Extensions	4	24	1	68	–	52	2	107
Infill Drilling	6	20	–	10	–	16	1	40
Improved Recovery	–	–	5	–	–	–	–	5
Acquisitions	1	–	–	–	–	43	1	9
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	4	–	–	–	14	(37)	(1)	11
Technical Revisions	6	31	(1)	50	153	56	5	253
Production	(29)	(46)	(14)	(36)	(31)	(446)	(9)	(239)
December 31, 2012	443	204	267	1,066	2,255	4,136	94	5,018

Reconciliation of Company Gross Reserves by Product
As of December 31, 2012
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, 2011	41	74	112	752	1,236	1,572	39	2,516
Discoveries	–	–	–	–	–	5	–	1
Extensions	4	10	–	277	–	38	3	301
Infill Drilling	6	8	–	5	–	10	–	20
Improved Recovery	–	–	3	–	–	–	–	3
Acquisitions	–	–	–	–	–	15	–	3
Dispositions	–	–	–	–	–	(2)	–	(1)
Economic Factors	–	–	–	–	(11)	(2)	–	(11)
Technical Revisions	–	(12)	(10)	22	(129)	(47)	2	(135)
Production	–	–	–	–	–	–	–	–
December 31, 2012	51	80	105	1,056	1,096	1,589	44	2,697

North Sea

	Light and Medium Oil MMbbl	Natural Gas Bcf	Barrels of Oil Equivalent MMBOE
December 31, 2011	121	36	127
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	–	–	–
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	(4)	(1)	(4)
Technical Revisions	(12)	(15)	(14)
Production	–	–	–
December 31, 2012	105	20	109

Offshore Africa

	Light and Medium Oil MMbbl	Natural Gas Bcf	Barrels of Oil Equivalent MMBOE
December 31, 2011	56	46	64
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	1	–	1
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	–	–	–
Technical Revisions	(2)	(4)	(3)
Production	–	–	–
December 31, 2012	55	42	62

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, 2011	218	74	112	752	1,236	1,654	39	2,707
Discoveries	–	–	–	–	–	5	–	1
Extensions	4	10	–	277	–	38	3	301
Infill Drilling	7	8	–	5	–	10	–	21
Improved Recovery	–	–	3	–	–	–	–	3
Acquisitions	–	–	–	–	–	15	–	3
Dispositions	–	–	–	–	–	(2)	–	(1)
Economic Factors	(4)	–	–	–	(11)	(3)	–	(15)
Technical Revisions	(14)	(12)	(10)	22	(129)	(66)	2	(152)
Production	–	–	–	–	–	–	–	–
December 31, 2012	211	80	105	1,056	1,096	1,651	44	2,868

Reconciliation of Company Gross Reserves by Product
As of December 31, 2012
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, 2011	155	249	388	1,726	3,355	5,838	134	6,980
Discoveries	–	–	–	–	–	11	–	2
Extensions	8	34	1	345	–	90	5	408
Infill Drilling	11	28	–	15	–	26	1	59
Improved Recovery	–	–	8	–	–	–	–	8
Acquisitions	1	–	–	–	–	58	1	12
Dispositions	–	–	–	–	–	(3)	–	(1)
Economic Factors	–	–	–	–	3	(40)	(1)	(4)
Technical Revisions	4	19	(11)	72	24	32	7	120
Production	(15)	(46)	(14)	(36)	(31)	(438)	(9)	(224)
December 31, 2012	164	284	372	2,122	3,351	5,574	138	7,360

North Sea

December 31, 2011	349					134		371
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(10)					(31)		(15)
Production	(7)					(1)		(7)
December 31, 2012	332					102		349

Offshore Africa

December 31, 2011	165					129		187
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	2					–		2
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(2)					(11)		(4)
Production	(7)					(7)		(8)
December 31, 2012	158					111		177

Total Company

December 31, 2011	669	249	388	1,726	3,355	6,101	134	7,538
Discoveries	–	–	–	–	–	11	–	2
Extensions	8	34	1	345	–	90	5	408
Infill Drilling	13	28	–	15	–	26	1	61
Improved Recovery	–	–	8	–	–	–	–	8
Acquisitions	1	–	–	–	–	58	1	12
Dispositions	–	–	–	–	–	(3)	–	(1)
Economic Factors	–	–	–	–	3	(40)	(1)	(4)
Technical Revisions	(8)	19	(11)	72	24	(10)	7	101
Production	(29)	(46)	(14)	(36)	(31)	(446)	(9)	(239)
December 31, 2012	654	284	372	2,122	3,351	5,787	138	7,886

(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:

	2013	2014	2015	2016	2017	Average annual increase thereafter
Crude oil and NGLs						
WTI at Cushing (US$/bbl)	*$ 89.63*	*$ 89.93*	*$ 88.29*	*$ 95.52*	*$ 96.96*	*1.5%*
Western Canada Select (C$/bbl)	*$ 69.33*	*$ 74.57*	*$ 73.21*	*$ 80.17*	*$ 81.37*	*1.5%*
Edmonton Par (C$/bbl)	*$ 84.55*	*$ 89.84*	*$ 88.21*	*$ 95.43*	*$ 96.87*	*1.5%*
Edmonton Pentanes+ (C$/bbl)	*$ 90.53*	*$ 96.19*	*$ 94.44*	*$ 102.18*	*$ 103.71*	*1.5%*
North Sea Brent (US$/bbl)	*$ 106.42*	*$ 101.65*	*$ 97.56*	*$ 105.07*	*$ 106.65*	*1.5%*
Natural gas						
AECO (C$/MMBtu)	*$ 3.31*	*$ 3.72*	*$ 3.91*	*$ 4.70*	*$ 5.32*	*1.5%*
BC Westcoast Station 2 (C$/MMBtu)	*$ 3.25*	*$ 3.66*	*$ 3.85*	*$ 4.64*	*$ 5.26*	*1.5%*
Henry Hub Louisiana (US$/MMBtu)	*$ 3.65*	*$ 4.06*	*$ 4.24*	*$ 5.04*	*$ 5.66*	*1.5%*

A foreign exchange rate of 1.001 US$/Cdn$ was used in the 2012 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", "proposed" 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, 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 expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia, 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, natural gas and natural gas liquids ("NGLs") 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 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, 2012 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2011.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's consolidated financial statements for the period ended December 31, 2012 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. 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 ("Mcf") of natural gas to one barrel ("bbl") 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 and 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, 2012 in relation to the comparable periods in 2011 and the third quarter of 2012. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2011, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated March 6, 2013.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Product sales	**$ 4,059**	$ 3,978	$ 4,788	**$ 16,195**	$ 15,507
Net earnings	**$ 352**	$ 360	$ 832	**$ 1,892**	$ 2,643
Per common share – basic	**$ 0.32**	$ 0.33	$ 0.76	**$ 1.72**	$ 2.41
– diluted	**$ 0.32**	$ 0.33	$ 0.76	**$ 1.72**	$ 2.40
Adjusted net earnings from operations (1)	**$ 359**	$ 353	$ 972	**$ 1,618**	$ 2,540
Per common share – basic	**$ 0.33**	$ 0.33	$ 0.89	**$ 1.48**	$ 2.32
– diluted	**$ 0.33**	$ 0.32	$ 0.88	**$ 1.47**	$ 2.30
Cash flow from operations (2)	**$ 1,548**	$ 1,431	$ 2,158	**$ 6,013**	$ 6,547
Per common share – basic	**$ 1.41**	$ 1.31	$ 1.97	**$ 5.48**	$ 5.98
– diluted	**$ 1.41**	$ 1.30	$ 1.96	**$ 5.47**	$ 5.94
Capital expenditures, net of dispositions	**$ 1,767**	$ 1,621	$ 1,909	**$ 6,308**	$ 6,414

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

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

Adjusted Net Earnings from Operations

($ millions)	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Net earnings as reported	**$ 352**	$ 360	$ 832	**$ 1,892**	$ 2,643
Share-based compensation, net of tax (1)	**(41)**	49	207	**(214)**	(102)
Unrealized risk management loss (gain), net of tax (2)	**4**	22	50	**(37)**	(95)
Unrealized foreign exchange loss (gain), net of tax (3)	**254**	(136)	(117)	**129**	215
Realized foreign exchange gain on repayment of US dollar debt securities (4)	**(210)**	–	–	**(210)**	(225)
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (5)	**–**	58	–	**58**	104
Adjusted net earnings from operations	**$ 359**	$ 353	$ 972	**$ 1,618**	$ 2,540

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

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

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

(4) During the fourth quarter of 2012, the Company repaid US$350 million of 5.45% unsecured notes. During the third quarter of 2011, the Company repaid US$400 million of 6.70% unsecured notes.

(5) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. During the third quarter of 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax rate relief on UK North Sea decommissioning expenditures to 50%, resulting in an increase in the Company's deferred income tax liability of $58 million. During the first quarter of 2011, the UK government enacted legislation to increase the corporate income tax rate charged on profits from UK North Sea crude oil and natural gas production from 50% to 62%. The Company's deferred income tax liability was increased by $104 million with respect to this tax rate change.

Cash Flow from Operations

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2012**	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Net earnings	**$ 352**	$ 360	$ 832	**$ 1,892**	$ 2,643
Non-cash items:					
Depletion, depreciation and amortization	**1,213**	1,056	998	**4,328**	3,604
Share-based compensation	**(41)**	49	207	**(214)**	(102)
Asset retirement obligation accretion	**38**	38	33	**151**	130
Unrealized risk management loss (gain)	**8**	34	58	**(42)**	(128)
Unrealized foreign exchange loss (gain)	**254**	(136)	(117)	**129**	215
Realized foreign exchange gain on repayment of US dollar debt securities	**(210)**	–	–	**(210)**	(225)
Equity loss from jointly controlled entity	**3**	1	–	**9**	–
Deferred income tax (recovery) expense	**(69)**	29	144	**(30)**	407
Horizon asset impairment provision	**–**	–	–	**–**	396
Insurance recovery – property damage	**–**	–	3	**–**	(393)
Cash flow from operations	**$ 1,548**	$ 1,431	$ 2,158	**$ 6,013**	$ 6,547

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the year ended December 31, 2012 were $1,892 million compared with $2,643 million for the year ended December 31, 2011. Net earnings for the year ended December 31, 2012 included net after-tax income of $274 million compared with $103 million for the year ended December 31, 2011 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of a 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. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2012 were $1,618 million compared with $2,540 million for the year ended December 31, 2011.

Net earnings for the fourth quarter of 2012 were $352 million compared with $832 million for the fourth quarter of 2011 and $360 million for the third quarter of 2012. Net earnings for the fourth quarter of 2012 included net after-tax expenses of $7 million compared with $140 million for the fourth quarter of 2011 and net after-tax income of $7 million for the third quarter of 2012 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of a 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. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2012 were $359 million compared with $972 million for the fourth quarter of 2011 and $353 million for the third quarter of 2012.

The decrease in adjusted net earnings for the year ended December 31, 2012 from the year ended December 31, 2011 was primarily due to:

- lower crude oil and NGLs and natural gas netbacks;
- lower realized synthetic crude oil (“SCO”) prices;
- higher depletion, depreciation and amortization expense; and
- higher realized risk management losses;

partially offset by:

- higher crude oil and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments.

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

- lower crude oil and NGLs and natural gas netbacks;
- lower realized SCO prices;
- lower natural gas sales volumes;
- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- higher depletion, depreciation and amortization expense; and
- the impact of a stronger Canadian dollar;

partially offset by:

- higher crude oil sales volumes in the North America segment.

The adjusted net earnings for the fourth quarter of 2012 were comparable with the third quarter of 2012.

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

Cash flow from operations for the year ended December 31, 2012 was $6,013 million compared with $6,547 million for the year ended December 31, 2011. Cash flow from operations for the fourth quarter of 2012 was $1,548 million compared with $2,158 million for the fourth quarter of 2011 and $1,431 million for the third quarter of 2012. The fluctuations in cash flow from operations from the comparable periods was primarily due to the factors noted above relating to the fluctuations in adjusted net earnings, excluding depletion, depreciation and amortization expense, as well as due to the impact of cash taxes.

Total production before royalties for the year ended December 31, 2012 increased 9% to 654,665 BOE/d from 598,526 BOE/d for the year ended December 31, 2011. Total production before royalties for the fourth quarter of 2012 was comparable with the fourth quarter of 2011 and the third quarter of 2012.

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 2012**		Sep 30 2012		Jun 30 2012		Mar 31 2012
Product sales	**$**	**4,059**	$	3,978	$	4,187	$	3,971
Net earnings	**$**	**352**	$	360	$	753	$	427
Net earnings per common share								
– basic	**$**	**0.32**	$	0.33	$	0.68	$	0.39
– diluted	**$**	**0.32**	$	0.33	$	0.68	$	0.39

($ 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

Volatility in the quarterly net earnings 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 from West Texas Intermediate ("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.
- **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, the record heavy oil drilling program, 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, shut-in natural gas production due to pricing and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America, acquisitions of natural gas producing properties in 2011 that had higher operating costs per Mcf than the Company's existing properties, and the suspension and recommencement of production at Horizon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, and the impact of the suspension and recommencement of production at Horizon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Changes in the Canadian dollar relative to the US dollar that impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses are recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
WTI benchmark price (US$/bbl)	**$ 88.20**	$ 92.19	$ 94.02	**$ 94.19**	$ 95.14
Dated Brent benchmark price (US$/bbl)	**$ 110.03**	$ 109.57	$ 109.29	**$ 111.56**	$ 111.29
WCS blend differential from WTI (US$/bbl)	**$ 18.15**	$ 21.78	$ 10.49	**$ 21.05**	$ 17.10
WCS blend differential from WTI (%)	**21%**	24%	11%	**22%**	18%
SCO price (US$/bbl)	**$ 91.90**	$ 90.84	$ 102.95	**$ 92.59**	$ 103.63
Condensate benchmark price (US$/bbl)	**$ 98.13**	$ 96.09	$ 108.68	**$ 100.92**	$ 105.38
NYMEX benchmark price (US$/MMBtu)	**$ 3.36**	$ 2.82	$ 3.61	**$ 2.80**	$ 4.07
AECO benchmark price (C$/GJ)	**$ 2.89**	$ 2.08	$ 3.29	**$ 2.28**	$ 3.48
US/Canadian dollar average exchange rate (US$)	**$ 1.0088**	$ 1.0047	$ 0.9773	**$ 1.0004**	$ 1.0111

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$94.19 per bbl for the year ended December 31, 2012, a decrease of 1% from US$95.14 per bbl for the year ended December 31, 2011. WTI averaged US$88.20 per bbl for the fourth quarter of 2012, a decrease of 6% from US$94.02 per bbl for the fourth quarter of 2011, and a decrease of 4% from US$92.19 per bbl for the third quarter of 2012. WTI pricing was reflective of the political instability in the Middle East, the declining optimism in the United States economy related to the fiscal cliff, the European debt crisis, and lower than expected growth in Asian demand.

Crude oil sales contracts for the Company’s North Sea and Offshore Africa segments are typically based on Dated Brent (“Brent”) pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$111.56 per bbl for the year ended December 31, 2012 and was comparable with the year ended December 31, 2011. Brent averaged US$110.03 per bbl for the fourth quarter of 2012 and was comparable with the comparative periods. The higher Brent pricing relative to WTI was due to logistical constraints and high inventory levels of crude oil at Cushing.

The WCS Heavy Differential averaged 22% for the year ended December 31, 2012 compared with 18% for the year ended December 31, 2011. The WCS Heavy Differential averaged 21% for the fourth quarter of 2012, compared with 11% in the fourth quarter of 2011, and 24% for the third quarter of 2012. The WCS Heavy Differential for October and November 2012 narrowed, averaging 11% and 16% respectively. The WCS Heavy Differential widened in December 2012 to average 34% as a result of unplanned Enbridge pipeline capacity limitations and refinery plans to lower crude inventories for year end. The impact of higher WCS Heavy Differentials in January and February 2013 of 35% and 39% respectively were partially offset by higher overall WTI benchmark pricing. The WCS Heavy Differential narrowed in March 2013 to average approximately 29%.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During the fourth quarter of 2012, condensate prices continued to trade at a premium to WTI, similar to prior periods, reflecting normal seasonality.

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 economic recovery. The WCS Heavy Differential is expected to continue to reflect seasonal demand fluctuations, changes in transportation logistics, and refinery utilization and shutdowns.

NYMEX natural gas prices averaged US$2.80 per MMBtu for the year ended December 31, 2012, a decrease of 31% from US$4.07 per MMBtu for the year ended December 31, 2011. NYMEX natural gas prices averaged US$3.36 per MMBtu for the fourth quarter of 2012, a decrease of 7% from US$3.61 per MMBtu for the fourth quarter of 2011, and an increase of 19% from US$2.82 per MMBtu for the third quarter of 2012.

AECO natural gas prices for the year ended December 31, 2012 averaged $2.28 per GJ, a decrease of 34% from $3.48 per GJ for the year ended December 31, 2011. AECO natural gas prices for the fourth quarter of 2012 averaged $2.89 per GJ, a decrease of 12% from $3.29 per GJ for the fourth quarter of 2011, and an increase of 39% from $2.08 per GJ for the third quarter of 2012.

During the fourth quarter of 2012, natural gas prices continued to recover from the low pricing levels in 2012. While Canadian production has declined in response to low prices, US production has held steady during 2012. Natural gas pricing continues to be volatile as the market still requires a shift to higher utilization of gas fired electric generation to offset the strong North America supply position.

The Company continues to focus on its crude oil marketing strategy including a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that provide crude oil transportation to new markets, and supporting incremental heavy crude oil conversion capacity. During the fourth quarter of 2012, the Company entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Kinder Morgan Trans Mountain Expansion from Edmonton, Alberta to Vancouver, British Columbia. The regulatory approval process will begin in 2013 with a planned in-service date in 2017.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**351,983**	332,895	291,839	**326,829**	295,618
North America – Oil Sands Mining and Upgrading	**83,079**	99,205	102,952	**86,077**	40,434
North Sea	**19,140**	19,502	26,769	**19,824**	29,992
Offshore Africa	**15,762**	17,566	22,726	**18,648**	23,009
	469,964	469,168	444,286	**451,378**	389,053
Natural gas (MMcf/d)					
North America	**1,113**	1,169	1,255	**1,198**	1,231
North Sea	**1**	2	6	**2**	7
Offshore Africa	**20**	20	19	**20**	19
	1,134	1,191	1,280	**1,220**	1,257
Total barrels of oil equivalent (BOE/d)	**658,973**	667,616	657,599	**654,665**	598,526
Product mix					
Light and medium crude oil and NGLs	**15%**	15%	17%	**16%**	18%
Pelican Lake heavy crude oil	**5%**	6%	6%	**6%**	6%
Primary heavy crude oil	**20%**	19%	17%	**19%**	18%
Bitumen (thermal oil)	**18%**	15%	12%	**15%**	16%
Synthetic crude oil	**13%**	15%	16%	**13%**	7%
Natural gas	**29%**	30%	32%	**31%**	35%
Percentage of product sales (1) (excluding midstream revenue)					
Crude oil and NGLs	**89%**	92%	90%	**91%**	86%
Natural gas	**11%**	8%	10%	**9%**	14%

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**305,577**	261,655	230,522	**273,374**	240,006
North America – Oil Sands Mining and Upgrading	**79,691**	95,704	98,287	**82,171**	38,721
North Sea	**19,096**	19,441	26,714	**19,772**	29,919
Offshore Africa	**10,358**	11,662	19,331	**13,628**	20,532
	414,722	388,462	374,854	**388,945**	329,178
Natural gas (MMcf/d)					
North America	**1,047**	1,159	1,211	**1,171**	1,186
North Sea	**1**	2	6	**2**	7
Offshore Africa	**16**	16	16	**17**	16
	1,064	1,177	1,233	**1,190**	1,209
Total barrels of oil equivalent (BOE/d)	**592,080**	584,577	580,242	**587,246**	530,576

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, 2012 increased 16% to 451,378 bbl/d from 389,053 bbl/d for the year ended December 31, 2011. Crude oil and NGLs production for the fourth quarter of 2012 increased 6% to 469,964 bbl/d from 444,286 bbl/d for the fourth quarter of 2011 and was comparable with the third quarter of 2012. The increase in production from the comparable periods in 2011 was primarily related to the impact of a strong heavy crude oil drilling program and the cyclic nature of the Company's thermal operations. Crude oil and NGLs production in the fourth quarter of 2012 was within the Company's previously issued guidance of 467,000 to 495,000 bbl/d.

Natural gas production for the year ended December 31, 2012 decreased 3% to 1,220 MMcf/d from 1,257 MMcf/d for the year ended December 31, 2011. Natural gas production for the fourth quarter of 2012 decreased 11% to 1,134 MMcf/d from 1,280 MMcf/d for the fourth quarter of 2011 and decreased 5% from 1,191 MMcf/d for the third quarter of 2012. The decrease in natural gas production for the three months and year ended December 31, 2012 from the comparable periods was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines. During the fourth quarter of 2012, certain gas processing contract arrangements were ended to provide greater flexibility of cost control, resulting in the shut in of additional natural gas production. As a result of the shut-in natural gas, natural gas production in the fourth quarter of 2012 was slightly below the Company's previously issued guidance of 1,145 to 1,165 MMcf/d.

For 2013, annual production guidance is targeted to average between 482,000 and 513,000 bbl/d of crude oil and NGLs and between 1,085 and 1,145 MMcf/d of natural gas. First quarter 2013 production guidance is targeted to average between 471,000 and 495,000 bbl/d of crude oil and NGLs and between 1,130 and 1,150 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2012 increased 11% to average 326,829 bbl/d from 295,618 bbl/d for the year ended December 31, 2011. For the fourth quarter of 2012, crude oil and NGLs production increased 21% to average 351,983 bbl/d compared with 291,839 bbl/d for the fourth quarter of 2011 and increased 6% from 332,895 bbl/d in the third quarter of 2012. Increases in crude oil and NGLs production from comparable periods were primarily due to the impact of a strong heavy crude oil drilling program and the cyclic nature of the Company's thermal operations. Fourth quarter 2012 production of crude oil and NGLs was within the Company's previously issued guidance of 350,000 bbl/d to 365,000 bbl/d. First quarter 2013 production guidance is targeted to average between 335,000 and 349,000 bbl/d for crude oil and NGLs.

Natural gas production for the year ended December 31, 2012 decreased 3% to 1,198 MMcf/d compared with 1,231 MMcf/d for the year ended December 31, 2011. Natural gas production decreased 11% to 1,113 MMcf/d for the fourth quarter of 2012 compared with 1,255 MMcf/d in the fourth quarter of 2011 and decreased 5% from 1,169 MMcf/d in the third quarter of 2012. The decrease in natural gas production for the three months and year ended December 31, 2012 from the comparable periods was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines. During the fourth quarter of 2012, certain gas processing contract arrangements were ended to provide greater flexibility of cost control, resulting in the shut in of additional natural gas production.

North America – Oil Sands Mining and Upgrading

Production averaged 86,077 bbl/d for the year ended December 31, 2012 compared with 40,434 bbl/d for the year ended December 31, 2011. For the fourth quarter of 2012, SCO production averaged 83,079 bbl/d compared with 102,952 bbl/d for the fourth quarter of 2011 and 99,205 bbl/d for the third quarter of 2012. Production for the year ended December 31, 2012 increased from the comparable period in 2011 as a result of the suspension of production during a portion of 2011. Fourth quarter production in 2012 decreased from the fourth quarter of 2011 and the third quarter of 2012 as the Company completed a 12 day planned maintenance outage in October 2012 as well as additional maintenance in the ore preparation plants in December 2012. Production of SCO was slightly below the Company's previously issued guidance of 85,000 to 92,000 bbl/d for the fourth quarter of 2012. First quarter 2013 production guidance is targeted to average between 105,000 and 111,000 bbl/d.

North Sea

North Sea crude oil production for the year ended December 31, 2012 decreased 34% to 19,824 bbl/d from 29,992 bbl/d for the year ended December 31, 2011. For the fourth quarter of 2012, North Sea crude oil production decreased 28% to 19,140 bbl/d from 26,769 bbl/d for the fourth quarter of 2011, and decreased 2% from 19,502 bbl/d in the third quarter of 2012. The decrease in production volumes for the three months and year ended December 31, 2012 from the comparable periods was primarily due to temporary shut ins of the third-party operated pipeline to Sullom Voe, which caused all Ninian and associated fields to be shut in for a portion of the third and fourth quarters of 2012, the suspension of production at Banff/Kyle, and natural field declines. In addition, the Company accelerated its fourth quarter 2012 planned turnaround activity to mitigate the impact of the pipeline outage.

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. The FPSO and associated floating storage unit have subsequently been removed from the field and the FPSO is currently in dry dock for assessment of damages and repair timeframe. The extent of the property damage, including associated costs, is not expected to be significant.

Offshore Africa

Offshore Africa crude oil production decreased 19% to 18,648 bbl/d for the year ended December 31, 2012 from 23,009 bbl/d for the year ended December 31, 2011. Fourth quarter 2012 crude oil production averaged 15,762 bbl/d, decreasing 31% from 22,726 bbl/d for the fourth quarter of 2011 and decreasing 10% from 17,566 bbl/d in the third quarter of 2012. The decrease in production volumes for the three months and year ended December 31, 2012 from the comparable periods was due to natural field declines, planned turnaround activity at Espoir, and the shut in of approximately 1,500 bbl/d of production at the Olowi field, Gabon. The Company currently has a vessel on-site in Gabon assessing the operability of the midwater arch.

International Guidance

The Company's North Sea and Offshore Africa fourth quarter 2012 crude oil and NGLs production was within the Company's previously issued guidance of 32,000 to 38,000 bbl/d. First quarter 2013 production guidance is targeted to average between 31,000 and 35,000 bbl/d of crude oil.

Crude Oil Inventory Volumes

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

(bbl)	**Dec 31 2012**	Sep 30 2012	Dec 31 2011
North America – Exploration and Production	**643,758**	656,340	557,475
North America – Oil Sands Mining and Upgrading (SCO)	**993,627**	888,442	1,021,236
North Sea	**77,018**	150,269	286,633
Offshore Africa	**1,036,509**	1,058,992	527,312
	2,750,912	2,754,043	2,392,656

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 64.23**	$ 67.59	$ 85.28	**$ 70.24**	$ 77.46
Royalties	**8.59**	12.08	15.53	**10.67**	12.30
Production expense	**15.32**	15.79	16.85	**16.11**	15.75
Netback	**$ 40.32**	$ 39.72	$ 52.90	**$ 43.46**	$ 49.41
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 3.16**	$ 2.28	$ 3.50	**$ 2.44**	$ 3.73
Royalties	**0.21**	0.05	0.18	**0.09**	0.18
Production expense	**1.43**	1.30	1.15	**1.31**	1.15
Netback	**$ 1.52**	$ 0.93	$ 2.17	**$ 1.04**	$ 2.40
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 49.83**	$ 49.08	$ 61.21	**$ 50.81**	$ 57.16
Royalties	**6.22**	7.94	10.14	**7.07**	8.12
Production expense	**13.11**	12.97	13.12	**13.14**	12.42
Netback	**$ 30.50**	$ 28.17	$ 37.95	**$ 30.60**	$ 36.62

(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 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 60.17**	$ 63.73	$ 81.02	**$ 65.54**	$ 72.17
North Sea	**$ 108.82**	$ 106.68	$ 109.71	**$ 110.75**	$ 108.56
Offshore Africa	**$ 97.97**	$ 112.59	$ 102.74	**$ 111.18**	$ 105.53
Company average	**$ 64.23**	$ 67.59	$ 85.28	**$ 70.24**	$ 77.46
Natural gas ($/Mcf) (1) (2)					
North America	**$ 3.03**	$ 2.15	$ 3.36	**$ 2.31**	$ 3.64
North Sea	**$ 2.67**	$ 3.65	$ 4.17	**$ 3.70**	$ 4.07
Offshore Africa	**$ 10.25**	$ 9.95	$ 12.79	**$ 10.17**	$ 9.56
Company average	**$ 3.16**	$ 2.28	$ 3.50	**$ 2.44**	$ 3.73
Company average ($/BOE) (1) (2)	**$ 49.83**	$ 49.08	$ 61.21	**$ 50.81**	$ 57.16

(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 decreased 9% to average $65.54 per bbl for the year ended December 31, 2012 from $72.17 per bbl for the year ended December 31, 2011. North America realized crude oil prices averaged $60.17 per bbl for the fourth quarter of 2012, a decrease of 26% compared with $81.02 per bbl for the fourth quarter of 2011 and a decrease of 6% compared with $63.73 per bbl for the third quarter of 2012. The decrease in prices for the three months and year ended December 31, 2012 from the comparable periods in 2011 was primarily a result of the lower WTI benchmark pricing, the widening of the WCS Heavy Differential and the fluctuations in the Canadian dollar relative to the US dollar. The decrease in prices for the fourth quarter of 2012 from the third quarter of 2012 was primarily due to the lower WTI benchmark pricing, partially offset by the narrowing of the WCS Heavy Differential. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2012 contributed approximately 165,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 37% to average $2.31 per Mcf for the year ended December 31, 2012 from $3.64 per Mcf for the year ended December 31, 2011. North America realized natural gas prices decreased 10% to average $3.03 per Mcf for the fourth quarter of 2012 compared with $3.36 per Mcf in the fourth quarter of 2011, and increased 41% compared with $2.15 per Mcf for the third quarter of 2012. The decrease in natural gas prices for the three months and year ended December 31, 2012 from the comparable periods in 2011 was primarily due to lower NYMEX and AECO benchmark pricing related to the impact of strong supply from US shale projects. The increase in natural gas prices for the fourth quarter of 2012 from the third quarter of 2012 was primarily due to higher NYMEX and AECO benchmark pricing related to a shift to higher utilization of gas fired electric generation and seasonality.

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

(Quarterly Average)	**Dec 31 2012**	Sep 30 2012	Dec 31 2011
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 68.67**	$ 67.33	$ 86.05
Pelican Lake heavy crude oil ($/bbl)	**$ 61.32**	$ 63.03	$ 81.64
Primary heavy crude oil ($/bbl)	**$ 59.42**	$ 61.54	$ 79.91
Bitumen (thermal oil) ($/bbl)	**$ 56.14**	$ 64.56	$ 78.38
Natural gas ($/Mcf)	**$ 3.03**	$ 2.15	$ 3.36

(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 2% to average $110.75 per bbl for the year ended December 31, 2012 from $108.56 per bbl for the year ended December 31, 2011. Realized crude oil prices averaged $108.82 per bbl for the fourth quarter of 2012, a decrease of 1% from $109.71 per bbl for the fourth quarter of 2011, and an increase of 2% from $106.68 per bbl for the third quarter of 2012. The fluctuations in realized crude oil prices in the North Sea from the comparable periods in 2011 were primarily the result of fluctuations in the Brent benchmark pricing and the Canadian dollar, and the timing of liftings.

Offshore Africa

Offshore Africa realized crude oil prices increased 5% to average $111.18 per bbl for the year ended December 31, 2012 from $105.53 per bbl for the year ended December 31, 2011. Realized crude oil prices decreased 5% to average $97.97 per bbl for the fourth quarter of 2012 from $102.74 per bbl for the fourth quarter of 2011, and decreased 13% from $112.59 per bbl for the third quarter of 2012. The fluctuations in realized crude oil prices in Offshore Africa from the comparable periods were primarily the result of the fluctuations in the Brent benchmark pricing and the Canadian dollar, and the timing of liftings.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 7.93**	$ 11.65	$ 17.10	**$ 10.33**	$ 13.51
North Sea	**$ 0.25**	$ 0.33	$ 0.23	**$ 0.29**	$ 0.26
Offshore Africa	**$ 33.59**	$ 37.84	$ 15.35	**$ 29.46**	$ 12.47
Company average	**$ 8.59**	$ 12.08	$ 15.53	**$ 10.67**	$ 12.30
Natural gas ($/Mcf) [1]					
North America	**$ 0.18**	$ 0.02	$ 0.15	**$ 0.06**	$ 0.16
Offshore Africa	**$ 1.74**	$ 1.89	$ 2.33	**$ 1.77**	$ 1.59
Company average	**$ 0.21**	$ 0.05	$ 0.18	**$ 0.09**	$ 0.18
Company average ($/BOE) [1]	**$ 6.22**	$ 7.94	$ 10.14	**$ 7.07**	$ 8.12

(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, 2012 compared with the year ended December 31, 2011 reflected benchmark commodity prices and the widening of the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 16% of product sales in 2012 compared with 19% in 2011. Crude oil and NGLs royalties averaged approximately 13% of product sales for the fourth quarter of 2012 compared with 21% for the fourth quarter of 2011 and 18% for the third quarter of 2012. The decrease in royalties from the comparable periods was the result of lower WTI benchmark pricing and changes in the WCS Heavy Differential. Crude oil and NGLs royalties per bbl are anticipated to average 16% to 18% of product sales for 2013.

Natural gas royalties averaged approximately 3% of product sales in 2012 compared with 4% in 2011. Natural gas royalties averaged approximately 6% of product sales for the fourth quarter of 2012 compared with 4% for the fourth quarter of 2011 and 1% for the third quarter of 2012. The fluctuations in natural gas royalty rates from the comparable periods were primarily the result of fluctuations in realized natural gas prices, together with gas cost allowance adjustments. Natural gas royalties are anticipated to average 4% to 6% of product sales for 2013.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 26% in 2012 compared with 17% in 2011. Royalty rates as a percentage of product sales averaged approximately 32% for the fourth and third quarters of 2012 compared with 18% for the fourth quarter of 2011. The increase in royalty rates from the comparable periods in 2011 was due to higher crude oil prices during the year, adjustments to royalties on liftings, and the payout of the Baobab field in May 2011.

Offshore Africa royalty rates are anticipated to average 9% to 11% of product sales for 2013.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 12.79**	$ 12.52	$ 14.32	**$ 13.40**	$ 13.21
North Sea	**$ 54.41**	$ 60.94	$ 36.45	**$ 53.53**	$ 37.06
Offshore Africa	**$ 22.14**	$ 38.34	$ 22.16	**$ 23.11**	$ 20.72
Company average	**$ 15.32**	$ 15.79	$ 16.85	**$ 16.11**	$ 15.75
Natural gas ($/Mcf) (1)					
North America	**$ 1.40**	$ 1.28	$ 1.12	**$ 1.28**	$ 1.12
North Sea	**$ 3.58**	$ 3.44	$ 3.51	**$ 3.75**	$ 2.83
Offshore Africa	**$ 3.19**	$ 2.37	$ 2.52	**$ 2.27**	$ 2.03
Company average	**$ 1.43**	$ 1.30	$ 1.15	**$ 1.31**	$ 1.15
Company average ($/BOE) (1)	**$ 13.11**	$ 12.97	$ 13.12	**$ 13.14**	$ 12.42

(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, 2012 averaged $13.40 per bbl and was comparable with the year ended December 31, 2011. North America crude oil and NGLs production expense for the fourth quarter of 2012 decreased 11% to $12.79 per bbl from $14.32 per bbl for the fourth quarter of 2011 and increased 2% from $12.52 per bbl for the third quarter of 2012. The increase in production expense for the three months ended December 31, 2012 from the third quarter of 2012 was primarily the result of higher servicing cost pressures in Heavy Oil. North America 2012 crude oil and NGLs production expense was slightly higher than the Company's previously issued guidance of $12.75 to $13.25 per bbl, and is anticipated to average $12.00 to $14.00 per bbl for 2013.

North America natural gas production expense for the year ended December 31, 2012 increased 14% to $1.28 per Mcf from $1.12 per Mcf for the year ended December 31, 2011. North America natural gas production expense for the fourth quarter of 2012 increased 25% to $1.40 per Mcf from $1.12 per Mcf for the fourth quarter of 2011 and increased 9% from $1.28 per Mcf for the third quarter of 2012. Natural gas production expense for the three months and year ended December 31, 2012 increased from the comparable periods due to the impact of shut-in production and lower production volumes related to the curtailment of capital expenditures related to natural gas activity. During the fourth quarter of 2012, certain gas processing contract arrangements were ended to provide greater flexibility of cost control, resulting in the shut in of additional natural gas production. North America 2012 natural gas production expense was slightly higher than the Company's previously issued guidance of $1.22 to $1.26 per Mcf, and is anticipated to average $1.30 to $1.40 per Mcf for 2013.

North Sea

North Sea crude oil production expense for the year ended December 31, 2012 increased 44% to $53.53 per bbl from $37.06 per bbl for the year ended December 31, 2011. North Sea crude oil production expense for the fourth quarter of 2012 decreased 11% to $54.41 per bbl from $60.94 per bbl for the third quarter of 2012 and increased 49% from $36.45 per bbl for the fourth quarter of 2011. Production expense decreased for the fourth quarter of 2012 from the third quarter of 2012 due to a reduced level of maintenance activity. Production expense increased on a per barrel basis for the three months and year ended December 31, 2012 from the comparable periods in 2011 due to the impact of production declines on relatively fixed costs, temporary shut ins of the third-party operated pipeline to Sullom Voe, and higher maintenance costs related to turnaround activity. North Sea 2012 crude oil production expense was slightly higher than the Company's previously issued guidance of $52.00 to $53.00 per bbl, and is anticipated to average $62.00 to $66.00 per bbl for 2013 due to natural declines on a relatively fixed cost structure.

Offshore Africa

Offshore Africa crude oil production expense increased 12% to $23.11 per bbl from $20.72 per bbl for the year ended December 31, 2012. Offshore Africa crude oil production expense for the fourth quarter of 2012 averaged $22.14 per bbl, comparable with the fourth quarter of 2011, and decreased 42% from $38.34 per bbl for the third quarter of 2012. Production expense for the three months and year ended December 31, 2012 fluctuated from the comparable periods as a result of the timing of liftings from various fields, which have different cost structures. Offshore Africa 2012 crude oil production expense was below the Company's previously issued guidance of $24.50 to $25.50 per bbl, and is anticipated to average $33.50 to $37.50 per bbl for 2013 due to timing of liftings from various fields.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Expense ($ millions)	**$ 1,097**	$ 931	$ 863	**$ 3,874**	$ 3,331
$/BOE (1)	**$ 20.66**	$ 18.00	$ 16.51	**$ 18.65**	$ 16.35

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

Depletion, depreciation and amortization expense increased for the three months and year ended December 31, 2012 compared with 2011 due to higher sales volumes in North America associated with heavy oil drilling and higher overall future development costs. The increase in depletion, depreciation and amortization expense from the third quarter of 2012 was primarily due to higher sales volumes in North America.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Expense ($ millions)	**$ 30**	$ 30	$ 28	**$ 119**	$ 110
$/BOE (1)	**$ 0.56**	$ 0.59	$ 0.54	**$ 0.57**	$ 0.54

(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

During October 2012, the Company completed a planned 12 day maintenance outage, as well as additional maintenance in the ore preparation plants during December 2012. These maintenance activities resulted in production of 83,079 bbl/d of SCO in the fourth quarter of 2012, which was slightly below the Company's previously issued guidance of 85,000 to 92,000 bbl/d of SCO. The Company continues to focus on efficient and effective operations at Horizon and place emphasis on safe, steady, reliable operations, resulting in January and February 2013 production of approximately 113,000 bbl/d and 107,000 bbl/d respectively. In the second quarter of 2013, Horizon will enter into a 24 day planned maintenance turnaround, resulting in a plant-wide shut down. The impact of the turnaround has been reflected in the Company's 2013 production, cash production cost and capital expenditure guidance.

PRODUCT PRICES AND ROYALTIES – OIL SANDS MINING AND UPGRADING

($/bbl) [1]	Three Months Ended Dec 31 2012	Sep 30 2012	Dec 31 2011	Year Ended Dec 31 2012	Dec 31 2011
SCO sales price [2]	**$ 87.34**	$ 87.40	$ 103.16	**$ 88.91**	$ 99.74
Bitumen value for royalty purposes [3]	**$ 58.12**	$ 57.40	$ 69.91	**$ 59.93**	$ 61.86
Bitumen royalties [4]	**$ 3.80**	$ 3.45	$ 4.21	**$ 4.34**	$ 3.99

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period during suspension of production.
(2) Net of transportation.
(3) Calculated as the simple quarterly average of the 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 $88.91 per bbl for the year ended December 31, 2012, a decrease of 11% compared with $99.74 per bbl for the year ended December 31, 2011. Realized SCO sales prices averaged $87.34 per bbl for the fourth quarter of 2012, a decrease of 15% compared with $103.16 per bbl for the fourth quarter of 2011 and were comparable with the third quarter of 2012, reflecting benchmark pricing and prevailing differentials.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

($ millions)	Three Months Ended Dec 31 2012	Sep 30 2012	Dec 31 2011	Year Ended Dec 31 2012	Dec 31 2011
Cash production costs	**$ 372**	$ 398	$ 344	**$ 1,504**	$ 1,127
Less: costs incurred during the period of suspension of production	**–**	–	–	**(154)**	(581)
Adjusted cash production costs	**$ 372**	$ 398	$ 344	**$ 1,350**	$ 546
Adjusted cash production costs, excluding natural gas costs	**$ 342**	$ 373	$ 316	**$ 1,254**	$ 502
Adjusted natural gas costs	**30**	25	28	**96**	44
Adjusted cash production costs	**$ 372**	$ 398	$ 344	**$ 1,350**	$ 546

($/bbl) [1]	Three Months Ended Dec 31 2012	Sep 30 2012	Dec 31 2011	Year Ended Dec 31 2012	Dec 31 2011
Adjusted cash production costs, excluding natural gas costs	**$ 45.31**	$ 40.03	$ 33.11	**$ 39.79**	$ 33.68
Adjusted natural gas costs	**3.96**	2.66	2.93	**3.04**	2.96
Adjusted cash production costs	**$ 49.27**	$ 42.69	$ 36.04	**$ 42.83**	$ 36.64
Sales (bbl/d)	**81,936**	101,263	103,710	**86,153**	40,847

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

Adjusted cash production costs averaged $42.83 per bbl for the year ended December 31, 2012, an increase of 17% compared with $36.64 per bbl for the year ended December 31, 2011. Adjusted cash production costs for the fourth quarter of 2012 averaged $49.27 per bbl, an increase of 37% compared with $36.04 per bbl for the fourth quarter of 2011 and an increase of 15% compared with $42.69 per bbl for the third quarter of 2012, primarily due to the impact of lower production volumes in the period. Cash production costs are anticipated to average $38.00 to $41.00 per bbl for 2013.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions)	Three Months Ended **Dec 31 2012**	Sep 30 2012	Dec 31 2011	Year Ended **Dec 31 2012**	Dec 31 2011
Depletion, depreciation and amortization	**$ 114**	$ 124	$ 133	**$ 447**	$ 266
Less: depreciation incurred during the period of suspension of production	**–**	–	–	**(6)**	(64)
Adjusted depletion, depreciation and amortization	**$ 114**	$ 124	$ 133	**$ 441**	$ 202
$/bbl (1)	**$ 15.12**	$ 13.31	$ 13.91	**$ 13.99**	$ 13.54

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

Depletion, depreciation and amortization expense reflects the impact of fluctuations in sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions)	Three Months Ended **Dec 31 2012**	Sep 30 2012	Dec 31 2011	Year Ended **Dec 31 2012**	Dec 31 2011
Expense	**$ 8**	$ 8	$ 5	**$ 32**	$ 20
$/bbl (1)	**$ 1.06**	$ 0.85	$ 0.52	**$ 1.01**	$ 1.33

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

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

MIDSTREAM

($ millions)	Three Months Ended **Dec 31 2012**	Sep 30 2012	Dec 31 2011	Year Ended **Dec 31 2012**	Dec 31 2011
Revenue	**$ 26**	$ 24	$ 22	**$ 93**	$ 88
Production expense	**8**	7	7	**29**	26
Midstream cash flow	**18**	17	15	**64**	62
Depreciation	**2**	1	2	**7**	7
Equity loss from jointly controlled entity	**3**	1	–	**9**	–
Segment earnings before taxes	**$ 13**	$ 15	$ 13	**$ 48**	$ 55

Midstream operating results were consistent with the comparable periods.

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 and refinery ("the Project") near Redwater, Alberta. In addition, the partnership has entered into processing agreements that target to process bitumen for the Company and the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement under the Bitumen Royalty In Kind initiative. In the fourth quarter of 2012, the Project was sanctioned by the Board of Directors of each partner of the North West Redwater Partnership ("Redwater"), and the associated target toll amounts were accepted by Redwater, the Company and the APMC.

ADMINISTRATION EXPENSE

($ millions)	Three Months Ended Dec 31 2012	Sep 30 2012	Dec 31 2011	Year Ended Dec 31 2012	Dec 31 2011
Expense	**$ 64**	$ 64	$ 47	**$ 270**	$ 235
$/BOE (1)	**$ 1.07**	$ 1.05	$ 0.76	**$ 1.13**	$ 1.07

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

Administration expense for the three months and year ended December 31, 2012 increased from the comparable periods in 2011 primarily due to higher staffing related costs and general corporate costs.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Dec 31 2012	Sep 30 2012	Dec 31 2011	Year Ended Dec 31 2012	Dec 31 2011
(Recovery) expense	**$ (41)**	$ 49	$ 207	**$ (214)**	$ (102)

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

The Company recorded a $214 million share-based compensation recovery for the year ended December 31, 2012, primarily as a result of remeasurement of the fair value of outstanding stock options at the end of the period related to a decrease in the Company's share price, partially offset by normal course graded vesting of stock options granted in prior periods and the impact of vested stock options exercised or surrendered during the period. For the year ended December 31, 2012, a $12 million recovery was recognized in respect of capitalized share-based compensation to Oil Sands Mining and Upgrading (December 31, 2011 – $nil).

For the year ended December 31, 2012, the Company paid $7 million for stock options surrendered for cash settlement (December 31, 2011 – $14 million).

INTEREST AND OTHER FINANCING COSTS

($ millions, except per BOE amounts)	Three Months Ended Dec 31 2012	Sep 30 2012	Dec 31 2011	Year Ended Dec 31 2012	Dec 31 2011
Expense, gross	**$ 115**	$ 119	$ 102	**$ 462**	$ 432
Less: capitalized interest	**32**	27	19	**98**	59
Expense, net	**$ 83**	$ 92	$ 83	**$ 364**	$ 373
$/BOE (1)	**$ 1.37**	$ 1.51	$ 1.35	**$ 1.52**	$ 1.71
Average effective interest rate	**4.8%**	4.9%	4.7%	**4.8%**	4.7%

(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, 2012 increased from the comparable period in 2011 due to higher variable interest rates and the impact of a weaker Canadian dollar on US dollar denominated debt; partially offset by lower average debt levels. Gross interest and other financing costs for the fourth quarter of 2012 increased from the comparable period in 2011 due to higher variable interest rates, partially offset by lower average debt levels and the impact of a stronger Canadian dollar on US dollar denominated debt. Gross interest and other financing costs were comparable with the third quarter of 2012. Capitalized interest of $98 million for the year ended December 31, 2012 was related to the Horizon Phase 2/3 expansion and the Kirby Thermal Oil Sands Project ("Kirby Project").

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2012**	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Crude oil and NGLs financial instruments	**$ 19**	$ 18	$ 27	**$ 65**	$ 117
Foreign currency contracts and interest rate swaps	**(27)**	119	(7)	**97**	(16)
Realized (gain) loss	**$ (8)**	$ 137	$ 20	**$ 162**	$ 101
Crude oil and NGLs financial instruments	**$ 29**	$ 58	$ 5	**$ 3**	$ (134)
Foreign currency contracts and interest rate swaps	**(21)**	(24)	53	**(45)**	6
Unrealized loss (gain)	**$ 8**	$ 34	$ 58	**$ (42)**	$ (128)
Net loss (gain)	**$ –**	$ 171	$ 78	**$ 120**	$ (27)

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

The Company recorded a net unrealized gain of $42 million ($37 million after-tax) on its risk management activities for the year ended December 31, 2012, including an unrealized loss of $8 million ($4 million after-tax) for the fourth quarter of 2012 (September 30, 2012 – unrealized loss of $34 million; $22 million after-tax; December 31, 2011 – unrealized loss of $58 million; $50 million after-tax).

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2012**	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Net realized (gain) loss	**$ (196)**	$ 21	$ 11	**$ (178)**	$ (214)
Net unrealized loss (gain) (1)	**254**	(136)	(117)	**129**	215
Net loss (gain)	**$ 58**	$ (115)	$ (106)	**$ (49)**	$ 1

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

The net realized foreign exchange gain for the year ended December 31, 2012 was primarily due to the repayment of US$350 million of 5.45% unsecured notes and foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange loss for the year ended December 31, 2012 was primarily related to the reversal of the life-to-date unrealized foreign exchange gain on the repayment of US$350 million of 5.45% unsecured notes; partially offset by the impact of the strengthening of the Canadian dollar with respect to remaining US dollar debt. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2012 – unrealized gain of $27 million, September 30, 2012 – unrealized loss of $85 million, December 31, 2011 – unrealized loss of $43 million; year ended December 31, 2012 – unrealized loss of $53 million, December 31, 2011 – unrealized gain of $42 million). The US/Canadian dollar exchange rate ended the fourth quarter of 2012 at US$1.0051 (September 30, 2012 – US$1.0166; December 31, 2011 – US$0.9833).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Dec 31 2012	Three Months Ended Sep 30 2012	Three Months Ended Dec 31 2011	Year Ended Dec 31 2012	Year Ended Dec 31 2011
North America [(1)]	**$ 68**	$ 61	$ 119	**$ 366**	$ 315
North Sea	**29**	22	84	**115**	245
Offshore Africa	**56**	50	50	**206**	140
PRT (recovery) expense – North Sea	**31**	(19)	39	**44**	135
Other taxes	**5**	–	7	**16**	25
Current income tax expense	**189**	114	299	**747**	860
Deferred income tax (recovery) expense	**(34)**	23	157	**–**	412
Deferred PRT (recovery) expense – North Sea	**(35)**	6	(13)	**(30)**	(5)
Deferred income tax (recovery) expense	**(69)**	29	144	**(30)**	407
	120	143	443	**717**	1,267
Income tax rate and other legislative changes	**–**	(58)	–	**(58)**	(104)
	$ 120	$ 85	$ 443	**$ 659**	$ 1,163
Effective income tax rate on adjusted net earnings from operations [(2)]	**25.5%**	23.8%	30.1%	**27.8%**	27.7%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) Excludes the impact of current and deferred PRT expense and other current income tax expense.

During the third quarter of 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on UK North Sea decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

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

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 2013, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $550 million to $650 million in Canada and $10 million to $100 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Dec 31 2012	Sep 30 2012	Dec 31 2011	Year Ended Dec 31 2012	Dec 31 2011
Exploration and Evaluation					
Net expenditures	**$ 10**	$ 59	$ 112	**$ 309**	$ 312
Property, Plant and Equipment					
Net property acquisitions	**76**	23	396	**144**	1,012
Well drilling, completion and equipping	**566**	485	585	**1,902**	1,878
Production and related facilities	**495**	533	480	**1,978**	1,690
Capitalized interest and other [2]	**23**	28	26	**111**	104
Net expenditures	**1,160**	1,069	1,487	**4,135**	4,684
Total Exploration and Production	**1,170**	1,128	1,599	**4,444**	4,996
Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**423**	354	150	**1,315**	481
Sustaining capital	**94**	41	44	**223**	170
Turnaround costs	**5**	11	–	**21**	79
Capitalized interest and other [2]	**19**	24	33	**51**	48
Total Oil Sands Mining and Upgrading	**541**	430	227	**1,610**	778
Horizon coker rebuild and collateral damage costs [3]	**–**	–	15	**–**	404
Midstream	**4**	5	–	**14**	5
Abandonments [4]	**41**	48	66	**204**	213
Head office	**11**	10	2	**36**	18
Total net capital expenditures	**$ 1,767**	$ 1,621	$ 1,909	**$ 6,308**	$ 6,414
By segment					
North America	**$ 1,086**	$ 1,029	$ 1,546	**$ 4,126**	$ 4,736
North Sea	**55**	79	71	**254**	227
Offshore Africa	**29**	20	(18)	**64**	33
Oil Sands Mining and Upgrading	**541**	430	242	**1,610**	1,182
Midstream	**4**	5	–	**14**	5
Abandonments [4]	**41**	48	66	**204**	213
Head office	**11**	10	2	**36**	18
Total	**$ 1,767**	$ 1,621	$ 1,909	**$ 6,308**	$ 6,414

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

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

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

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

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

Net capital expenditures for the year ended December 31, 2012 were $6,308 million, comparable with $6,414 million for the year ended December 31, 2011. Net capital expenditures for the fourth quarter of 2012 were $1,767 million compared with $1,909 million for the fourth quarter of 2011 and $1,621 million for the third quarter of 2012.

The increase in capital expenditures in the Exploration and Production and Oil Sands Mining and Upgrading segments for the year ended December 31, 2012 from the comparable period in 2011 was primarily due to the ramp up of Horizon site construction activity and an increase in production and related facilities spending, partially offset by lower net property acquisition costs. The decrease in capital expenditures for the fourth quarter of 2012 from the comparable period in 2011 was due to lower exploration and evaluation expenditures and lower net property acquisitions, partially offset by an increase in Horizon site construction costs. The increase in capital expenditures from the third quarter of 2012 was primarily due to an increase in well drilling and completion activities and an increase in Horizon site construction activity.

Drilling Activity (number of wells)

	Three Months Ended			Year Ended	
	Dec 31 2012	Sep 30 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Net successful natural gas wells	**3**	9	27	**35**	83
Net successful crude oil wells (1)	**294**	365	330	**1,203**	1,103
Dry wells	**19**	6	17	**33**	48
Stratigraphic test / service wells	**116**	22	112	**727**	657
Total	**432**	402	486	**1,998**	1,891
Success rate (excluding stratigraphic test / service wells)	**94%**	99%	95%	**97%**	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 69% of the total capital expenditures for the year ended December 31, 2012 compared with approximately 77% for the year ended December 31, 2011.

During the fourth quarter of 2012, the Company targeted 3 net natural gas wells, including 1 well in Northeast British Columbia and 2 wells in Northwest Alberta. The Company also targeted 313 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 226 primary heavy crude oil wells, 15 Pelican Lake heavy crude oil wells, 2 light crude oil wells and 38 bitumen (thermal oil) wells were drilled. Another 32 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall Primrose thermal production for the fourth quarter of 2012 averaged approximately 121,000 bbl/d compared with approximately 78,000 bbl/d for the fourth quarter of 2011 and approximately 102,000 bbl/d for the third quarter of 2012. Production volumes were in line with expectations due to the cyclic nature of thermal production at Primrose. As part of the phased expansion of its in situ Oil Sands assets, the Company is continuing to develop its Primrose thermal projects. Additional pad drilling was completed and drilled on budget, with these wells coming on production in 2013.

The next planned phase of the Company's in situ Oil Sands assets expansion is the Kirby South Phase 1 Project. As at December 31, 2012, the overall project was 81% complete, drilling was completed on the fifth of seven pads, and first steam is targeted for late 2013. In 2012, the Company acquired approximately 49 sections (12,630 hectares) of additional Oil Sands rights immediately adjacent to the Kirby Project.

Development of the tertiary recovery conversion projects at Pelican Lake continued and 15 horizontal wells were drilled during the quarter. Pelican Lake production averaged approximately 36,000 bbl/d for the fourth quarter of 2012 compared with 40,000 bbl/d for the fourth quarter of 2011 and 41,000 bbl/d for the third quarter of 2012. The decrease in production in the fourth quarter of 2012 from the third quarter of 2012 was a result of facility constraints, which will be alleviated as a result of the completion of the new 20,000 bbl/d battery expansion targeted to be on stream in the second quarter of 2013. With this incremental capacity, both Woodenhouse and Pelican production volumes will no longer be restricted.

For the first quarter of 2013, the Company's overall planned drilling activity in North America is expected to be 265 net crude oil wells, 31 net bitumen wells and 15 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the fourth quarter of 2012 was focused on the field construction of the gas recovery unit, sulphur recovery unit, butane treatment unit, coker expansion, and extraction trains 3 and 4, along with engineering related to the hydrogen and hydrotreater units, vacuum distillation unit and distillation recovery unit.

North Sea

In December 2011, the Banff FPSO and subsea infrastructure suffered storm damage. Operations at Banff/Kyle, with combined net production of approximately 3,500 bbl/d, were suspended. The FPSO and associated floating storage unit have subsequently been removed from the field and the FPSO is currently in dry dock for assessment of the damage and repair timeframe. The extent of the property damage, including associated costs, is not expected to be significant.

In September 2012, the UK government announced the implementation of the Brownfield Allowance, which allows for an agreed allowance related to property development for certain pre-approved qualifying field developments. This allowance partially mitigates the impact of previous tax increases. The Company is currently assessing the impact of this initiative on its future capital programs.

The Company currently plans to decommission the Murchison platform in the North Sea commencing in 2014 and estimates the decommissioning efforts will continue for approximately 5 years.

Offshore Africa

During the fourth quarter of 2011, the Company sanctioned an 8 well drilling program at the Espoir field in Côte d'Ivoire. Preparations are ongoing and a drilling rig is on-site in preparation for the commencement of the drilling program in 2013. At the Olowi field in Gabon, approximately 1,500 bbl/d of production was shut in due to a failure in the midwater arch. The Company currently has a vessel on-site assessing the operability of the midwater arch.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Dec 31 2012**	Sep 30 2012	Dec 31 2011
Working capital (deficit) (1)	**$ (1,264)**	$ (1,002)	$ (894)
Long-term debt (2) (3)	**$ 8,736**	$ 8,416	$ 8,571
Share capital	**$ 3,709**	$ 3,691	$ 3,507
Retained earnings	**20,516**	20,383	19,365
Accumulated other comprehensive income	**58**	46	26
Shareholders' equity	**$ 24,283**	$ 24,120	$ 22,898
Debt to book capitalization (3) (4)	**26%**	26%	27%
Debt to market capitalization (3) (5)	**22%**	20%	17%
After-tax return on average common shareholders' equity (6)	**8%**	10%	12%
After-tax return on average capital employed (3) (7)	**7%**	8%	10%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt.
(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.
(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.
(6) Calculated as net earnings for the twelve month trailing period; as a percentage of average common shareholders' equity for the period.
(7) Calculated as net earnings plus after-tax interest and other financing costs for the twelve month trailing period; as a percentage of average capital employed for the period.

At December 31, 2012, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's December 31, 2011 annual MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy. At December 31, 2012, the Company had $3,661 million of available credit under its bank credit facilities.

During the second quarter of 2012, the Company's $1,500 million revolving syndicated credit facility was extended to June 2016. Additionally, the Company issued $500 million of 3.05% medium-term notes due June 2019. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes. After issuing these securities, the Company has $2,500 million remaining on its outstanding $3,000 million base shelf prospectus that allows for the issue of medium-term notes in Canada, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

During the fourth quarter of 2012, the Company repaid US$350 million of 5.45% unsecured notes. The Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus that allows for the issue of US dollar debt securities in the United States, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

Subsequent to December 31, 2012, $400 million of 4.50% medium term notes and US$400 million of 5.15% unsecured notes were repaid. This indebtedness was retired utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities as necessary, while maintaining the ongoing dividend program. On a pro forma basis, reflecting the retirement of this indebtedness at December 31, 2012, the available credit under its bank credit facilities would amount to $2,863 million.

Long-term debt was $8,736 million at December 31, 2012, resulting in a debt to book capitalization ratio of 26% (September 30, 2012 – 26%; December 31, 2011 – 27%). This ratio is within the 25% 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 2013 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, 2012 are discussed in note 5 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedging policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at March 6, 2013, approximately 48% of currently forecasted 2013 crude oil volumes were hedged using price collars. Further details related to the Company's commodity related derivative financial instruments outstanding at December 31, 2012 are discussed in note 13 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at December 31, 2012, there were 1,092,072,000 common shares outstanding and 73,747,000 stock options outstanding. As at March 5, 2013, the Company had 1,092,589,000 common shares outstanding and 68,482,000 stock options outstanding.

During the second quarter of 2012, the Company amended its Articles by special resolution of the Shareholders, changing the designation of its Class 1 preferred shares to "Preferred Shares" which may be issuable in series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

On March 6, 2013, the Company's Board of Directors approved an increase in the annual dividend to be paid by the Company to $0.50 per common share for 2013. The increase represents an approximately 19% increase from 2012, recognizing the stability of the Company's cash flow and providing a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change. In March 2012, an increase in the annual dividend paid by the Company to $0.42 per common share was approved for 2012. The increase represented a 17% increase from 2011.

In April 2012, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), during the twelve month period commencing April 9, 2012 and ending April 8, 2013, up to 55,027,447 common shares.

On March 31, 2011, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the TSX and the NYSE, during the twelve month period commencing April 6, 2011 and ending April 5, 2012, up to 27,406,131 common shares of the Company.

As at December 31, 2012, 11,012,700 common shares were purchased for cancellation at a weighted average price of $28.91 per common share, for a total cost of $318 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, 2012, no entities were consolidated under the Standing Interpretations Committee ("SIC") 12, "Consolidation – Special Purpose Entities". The following table summarizes the Company's commitments as at December 31, 2012:

($ millions)		2013		2014		2015		2016		2017		Thereafter
Product transportation and pipeline	$	231	$	218	$	204	$	135	$	117	$	788
Offshore equipment operating leases and offshore drilling	$	156	$	135	$	104	$	76	$	57	$	65
Long-term debt (1)	$	798	$	846	$	593	$	1,027	$	1,094	$	4,430
Interest and other financing costs (2)	$	414	$	395	$	359	$	338	$	283	$	3,782
Office leases	$	33	$	34	$	32	$	33	$	35	$	262
Other	$	173	$	95	$	43	$	10	$	2	$	7

(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, 2012.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

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

CRITICAL ACCOUNTING ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

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

Consolidated Balance Sheets

As at (millions of Canadian dollars, unaudited)	Note		Dec 31 2012		Dec 31 2011
ASSETS					
Current assets					
Cash and cash equivalents		**$**	**37**	$	34
Accounts receivable			**1,197**		2,077
Inventory			**554**		550
Prepaids and other			**126**		120
			1,914		2,781
Exploration and evaluation assets	2		**2,611**		2,475
Property, plant and equipment	3		**44,028**		41,631
Other long-term assets	4		**427**		391
		$	**48,980**	$	47,278
LIABILITIES					
Current liabilities					
Accounts payable		**$**	**465**	$	526
Accrued liabilities			**2,273**		2,347
Current income tax liabilities			**285**		347
Current portion of long-term debt	5		**798**		359
Current portion of other long-term liabilities	6		**155**		455
			3,976		4,034
Long-term debt	5		**7,938**		8,212
Other long-term liabilities	6		**4,609**		3,913
Deferred income tax liabilities			**8,174**		8,221
			24,697		24,380
SHAREHOLDERS' EQUITY					
Share capital	9		**3,709**		3,507
Retained earnings			**20,516**		19,365
Accumulated other comprehensive income	10		**58**		26
			24,283		22,898
		$	**48,980**	$	47,278

Commitments and contingencies (note 14).

Approved by the Board of Directors on March 6, 2013

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Dec 31 2012	Three Months Ended Dec 31 2011	Year Ended Dec 31 2012	Year Ended Dec 31 2011
Product sales		**$ 4,059**	$ 4,788	**$ 16,195**	$ 15,507
Less: royalties		**(359)**	(570)	**(1,606)**	(1,715)
Revenue		**3,700**	4,218	**14,589**	13,792
Expenses					
Production		**1,072**	1,034	**4,249**	3,671
Transportation and blending		**738**	582	**2,752**	2,327
Depletion, depreciation and amortization	3	**1,213**	998	**4,328**	3,604
Administration		**64**	47	**270**	235
Share-based compensation	6	**(41)**	207	**(214)**	(102)
Asset retirement obligation accretion	6	**38**	33	**151**	130
Interest and other financing costs		**83**	83	**364**	373
Risk management activities	13	**–**	78	**120**	(27)
Foreign exchange loss (gain)		**58**	(106)	**(49)**	1
Horizon asset impairment provision	7	**–**	–	**–**	396
Insurance recovery – property damage	7	**–**	3	**–**	(393)
Insurance recovery – business interruption	7	**–**	(16)	**–**	(333)
Equity loss from jointly controlled entity	4	**3**	–	**9**	–
		3,228	2,943	**11,980**	9,882
Earnings before taxes		**472**	1,275	**2,609**	3,910
Current income tax expense	8	**189**	299	**747**	860
Deferred income tax (recovery) expense	8	**(69)**	144	**(30)**	407
Net earnings		**$ 352**	$ 832	**$ 1,892**	$ 2,643
Net earnings per common share					
Basic	12	**$ 0.32**	$ 0.76	**$ 1.72**	$ 2.41
Diluted	12	**$ 0.32**	$ 0.76	**$ 1.72**	$ 2.40

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2012	Three Months Ended Dec 31 2011	Year Ended Dec 31 2012	Year Ended Dec 31 2011
Net earnings	**$ 352**	$ 832	**$ 1,892**	$ 2,643
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $2 million (2011 – $10 million) – three months ended; $4 million (2011 – $5 million) – year ended	**17**	(67)	**31**	(23)
Reclassification to net earnings, net of taxes of $nil (2011 – $4 million) – three months ended; $nil (2011 – $17 million) – year ended	**(3)**	11	**(7)**	52
	14	(56)	**24**	29
Foreign currency translation adjustment				
Translation of net investment	**(2)**	11	**8**	(12)
Other comprehensive income (loss), net of taxes	**12**	(45)	**32**	17
Comprehensive income	**$ 364**	$ 787	**$ 1,924**	$ 2,660

Consolidated Statements of Changes in Equity

(millions of Canadian dollars, unaudited)	Note	Year Ended Dec 31 2012	Dec 31 2011
Share capital	9		
Balance – beginning of year		**$ 3,507**	$ 3,147
Issued upon exercise of stock options		**194**	255
Previously recognized liability on stock options exercised for common shares		**45**	115
Purchase of common shares under Normal Course Issuer Bid		**(37)**	(10)
Balance – end of year		**3,709**	3,507
Retained earnings			
Balance – beginning of year		**19,365**	17,212
Net earnings		**1,892**	2,643
Purchase of common shares under Normal Course Issuer Bid	9	**(281)**	(94)
Dividends on common shares	9	**(460)**	(396)
Balance – end of year		**20,516**	19,365
Accumulated other comprehensive income	10		
Balance – beginning of year		**26**	9
Other comprehensive income, net of taxes		**32**	17
Balance – end of year		**58**	26
Shareholders' equity		**$ 24,283**	$ 22,898

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Dec 31 2012	Three Months Ended Dec 31 2011	Year Ended Dec 31 2012	Year Ended Dec 31 2011
Operating activities					
Net earnings		**$ 352**	$ 832	**$ 1,892**	$ 2,643
Non-cash items					
Depletion, depreciation and amortization		**1,213**	998	**4,328**	3,604
Share-based compensation		**(41)**	207	**(214)**	(102)
Asset retirement obligation accretion		**38**	33	**151**	130
Unrealized risk management loss (gain)		**8**	58	**(42)**	(128)
Unrealized foreign exchange loss (gain)		**254**	(117)	**129**	215
Realized foreign exchange gain on repayment of US dollar debt securities		**(210)**	–	**(210)**	(225)
Equity loss from jointly controlled entity		**3**	–	**9**	–
Deferred income tax (recovery) expense		**(69)**	144	**(30)**	407
Horizon asset impairment provision	7	**–**	–	**–**	396
Insurance recovery – property damage	7	**–**	3	**–**	(393)
Other		**(94)**	(46)	**(47)**	(55)
Abandonment expenditures		**(41)**	(66)	**(204)**	(213)
Net change in non-cash working capital		**202**	267	**447**	(36)
		1,615	2,313	**6,209**	6,243
Financing activities					
Issue (repayment) of bank credit facilities, net		**592**	(1,632)	**172**	(647)
Issue of medium-term notes, net		**–**	–	**498**	–
(Repayment) issue of US dollar debt securities, net	5	**(344)**	1,011	**(344)**	621
Issue of common shares on exercise of stock options		**30**	63	**194**	255
Purchase of common shares under Normal Course Issuer Bid		**(118)**	(12)	**(318)**	(104)
Dividends on common shares		**(115)**	(99)	**(444)**	(378)
Net change in non-cash working capital		**(8)**	(5)	**(37)**	(15)
		37	(674)	**(279)**	(268)
Investing activities					
Expenditures on exploration and evaluation assets and property, plant and equipment		**(1,726)**	(1,843)	**(6,104)**	(6,201)
Investment in other long-term assets		**–**	25	**2**	(321)
Net change in non-cash working capital		**90**	195	**175**	559
		(1,636)	(1,623)	**(5,927)**	(5,963)
Increase in cash and cash equivalents		**16**	16	**3**	12
Cash and cash equivalents – beginning of period		**21**	18	**34**	22
Cash and cash equivalents – end of period		**$ 37**	$ 34	**$ 37**	$ 34
Interest paid		**$ 104**	$ 80	**$ 464**	$ 456
Income taxes paid		**$ 105**	$ 190	**$ 639**	$ 706

Notes to the Consolidated Financial Statements

(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, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater").

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

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

2. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2011	$ 2,442	$ –	$ 33	$ –	$ 2,475
Additions	**295**	**–**	**14**	**–**	**309**
Transfers to property, plant and equipment	**(173)**	**–**	**–**	**–**	**(173)**
At December 31, 2012	**$ 2,564**	**$ –**	**$ 47**	**$ –**	**$ 2,611**

3. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2011	$ 46,120	$ 4,147	$ 3,044	$ 15,211	$ 298	$ 234	$ 69,054
Additions	**4,160**	**556**	**75**	**1,757**	**14**	**36**	**6,598**
Transfers from E&E assets	**173**	**–**	**–**	**–**	**–**	**–**	**173**
Disposals/derecognitions	**(129)**	**(39)**	**(8)**	**(5)**	**–**	**–**	**(181)**
Foreign exchange adjustments and other	**–**	**(90)**	**(66)**	**–**	**–**	**–**	**(156)**
At December 31, 2012	**$ 50,324**	**$ 4,574**	**$ 3,045**	**$ 16,963**	**$ 312**	**$ 270**	**$ 75,488**
Accumulated depletion and depreciation							
At December 31, 2011	$ 21,721	$ 2,512	$ 2,152	$ 776	$ 96	$ 166	$ 27,423
Expense	**3,399**	**294**	**165**	**447**	**7**	**16**	**4,328**
Disposals/derecognitions	**(129)**	**(39)**	**(6)**	**(5)**	**–**	**–**	**(179)**
Foreign exchange adjustments and other	**–**	**(58)**	**(38)**	**(16)**	**–**	**–**	**(112)**
At December 31, 2012	**$ 24,991**	**$ 2,709**	**$ 2,273**	**$ 1,202**	**$ 103**	**$ 182**	**$ 31,460**
Net book value							
– at December 31, 2012	**$ 25,333**	**$ 1,865**	**$ 772**	**$ 15,761**	**$ 209**	**$ 88**	**$ 44,028**
– at December 31, 2011	$ 24,399	$ 1,635	$ 892	$ 14,435	$ 202	$ 68	$ 41,631

Horizon project costs not subject to depletion	
At December 31, 2012	**$ 2,066**
At December 31, 2011	$ 1,443

In addition, the Company has capitalized costs to date of $1,021 million (2011 – $528 million) related to the development of the Kirby Thermal Oil Sands Project which are not subject to depletion.

During 2012, 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 $144 million (year ended December 31, 2011 – $1,012 million), net of associated asset retirement obligations of $12 million (year ended December 31, 2011 – $79 million). Interests in jointly controlled assets were acquired with full tax basis. No working capital or debt obligations were assumed.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once construction is substantially complete. During 2012, pre-tax interest of $98 million was capitalized to property, plant and equipment (December 31, 2011 – $59 million) using a capitalization rate of 4.8% (December 31, 2011 – 4.7%).

4. OTHER LONG-TERM ASSETS

		Dec 31 2012		Dec 31 2011
Investment in North West Redwater Partnership	**$**	**310**	$	321
Other		**117**		70
	$	**427**	$	391

Other long-term assets include an investment in the 50% owned Redwater. The investment is accounted for using the equity method. Redwater has entered into an agreement to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission, an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement. During 2012, the Project received board sanction from Redwater and its partners.

Redwater has entered into various agreements related to the engineering and procurement of the Project. These contracts can be cancelled by Redwater upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

5. LONG-TERM DEBT

		Dec 31 2012		Dec 31 2011
Canadian dollar denominated debt				
Bank credit facilities	**$**	**971**	$	796
Medium-term notes		**1,300**		800
		2,271		1,596
US dollar denominated debt				
US dollar debt securities (December 31, 2012 – US$6,550 million; December 31, 2011 - US$6,900 million)		**6,517**		7,017
Less: original issue discount on US dollar debt securities (1)		**(20)**		(21)
		6,497		6,996
Fair value impact of interest rate swaps on US dollar debt securities (2)		**19**		31
		6,516		7,027
Long-term debt before transaction costs		**8,787**		8,623
Less: transaction costs (1) (3)		**(51)**		(52)
		8,736		8,571
Less: current portion (1) (2) (4)		**798**		359
	$	**7,938**	$	8,212

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

(2) The carrying amount of US$350 million of 4.90% unsecured notes due December 2014 was adjusted by $19 million to reflect the fair value impact of hedge accounting. At December 31, 2011, the carrying amounts of US$350 million of 5.45% unsecured notes due October 2012 and US$350 million of 4.90% unsecured notes due December 2014 were adjusted by $31 million to reflect the fair value impact of hedge accounting.

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

(4) Subsequent to December 31, 2012, $400 million of 4.50% medium term notes due January 2013 and US$400 million of 5.15% unsecured notes due February 2013 were repaid. This indebtedness was retired utilizing cash flow from operating activities generated in excess of capital expenditures and available bank credit facilities as necessary.

Bank Credit Facilities

As at December 31, 2012, the Company had in place unsecured bank credit facilities of $4,724 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $3,000 million maturing June 2015;
- a revolving syndicated credit facility of $1,500 million maturing June 2016; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During the second quarter of 2012, the $1,500 million revolving syndicated credit facility was extended to June 2016. Each of the $3,000 million and $1,500 million facilities is extendible annually for one-year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

The Company's weighted average interest rate on bank credit facilities outstanding as at December 31, 2012, was 2.2% (December 31, 2011 – 2.2%), and on long-term debt outstanding for the year ended December 31, 2012 was 4.8% (December 31, 2011 – 4.7%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $467 million, including an $87 million financial guarantee related to Horizon and $276 million of letters of credit related to North Sea operations, were outstanding at December 31, 2012. Subsequent to December 31, 2012, the letter of credit related to North Sea operations was increased to $347 million.

Medium-Term Notes

During the second quarter of 2012, the Company issued $500 million of 3.05% medium-term notes due June 2019. After issuing these securities, the Company has $2,500 million remaining on its outstanding $3,000 million base shelf prospectus that allows for the issue of medium-term notes in Canada, which expires in November 2013. If issued, these securities will bear interest as determined at the date of issuance.

US Dollar Debt Securities

During the fourth quarter of 2012, the Company repaid US$350 million of 5.45% unsecured notes.

During 2011, the Company repaid US$400 million of 6.70% unsecured notes and 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 13).

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

6. OTHER LONG-TERM LIABILITIES

	Dec 31 2012	Dec 31 2011
Asset retirement obligations	**$ 4,266**	$ 3,577
Share-based compensation	**154**	432
Risk management (note 13)	**257**	274
Other	**87**	85
	4,764	4,368
Less: current portion	**155**	455
	$ 4,609	$ 3,913

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 4.3% (December 31, 2011 – 4.6%). A reconciliation of the discounted asset retirement obligations is as follows:

	Dec 31 2012	Dec 31 2011
Balance – beginning of year	**$ 3,577**	$ 2,624
Liabilities incurred	**51**	42
Liabilities acquired	**12**	79
Liabilities settled	**(204)**	(213)
Asset retirement obligation accretion	**151**	130
Revision of estimates	**384**	472
Change in discount rate	**315**	422
Foreign exchange	**(20)**	21
Balance – end of year	**$ 4,266**	$ 3,577

Share-based compensation

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

	Dec 31 2012	Dec 31 2011
Balance – beginning of year	**$ 432**	$ 663
Share-based compensation recovery	**(214)**	(102)
Cash payment for stock options surrendered	**(7)**	(14)
Transferred to common shares	**(45)**	(115)
Recovered from Oil Sands Mining and Upgrading	**(12)**	–
Balance – end of year	**154**	432
Less: current portion	**129**	384
	$ 25	$ 48

7. HORIZON ASSET IMPAIRMENT PROVISION AND INSURANCE RECOVERY

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

8. INCOME TAXES

The provision for income tax is as follows:

	Three Months Ended		Year Ended	
	Dec 31 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Current corporate income tax – North America	**$ 68**	$ 119	**$ 366**	$ 315
Current corporate income tax – North Sea	**29**	84	**115**	245
Current corporate income tax – Offshore Africa	**56**	50	**206**	140
Current PRT [1] expense – North Sea	**31**	39	**44**	135
Other taxes	**5**	7	**16**	25
Current income tax expense	**189**	299	**747**	860
Deferred corporate income tax (recovery) expense	**(34)**	157	**–**	412
Deferred PRT [1] (recovery) – North Sea	**(35)**	(13)	**(30)**	(5)
Deferred income tax (recovery) expense	**(69)**	144	**(30)**	407
Income tax expense	**$ 120**	$ 443	**$ 717**	$ 1,267

(1) Petroleum Revenue Tax.

During the third quarter of 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on UK North Sea decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

During the first quarter of 2011, the UK government enacted legislation to increase 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.

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

9. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Year Ended Dec 31, 2012	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of year	**1,096,460**	**$ 3,507**
Issued upon exercise of stock options	**6,625**	**194**
Previously recognized liability on stock options exercised for common shares	**–**	**45**
Purchase of common shares under Normal Course Issuer Bid	**(11,013)**	**(37)**
Balance – end of year	**1,092,072**	**$ 3,709**

Preferred Shares

During the second quarter of 2012, the Company amended its Articles by special resolution of the Shareholders, changing the designation of its Class 1 preferred shares to “Preferred Shares” which may be issuable in series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

Dividend Policy

The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 6, 2013, the Board of Directors set the regular quarterly dividend at $0.125 per common share (2012 – $0.105 per common share).

Normal Course Issuer Bid

The Company’s Normal Course Issuer Bid announced in 2011 expired April 5, 2012. In April 2012, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the twelve month period commencing April 9, 2012 and ending April 8, 2013, up to 55,027,447 common shares.

As at December 31, 2012, the Company purchased 11,012,700 common shares at a weighted average price of $28.91 per common share, for a total cost of $318 million. Retained earnings were reduced by $281 million, representing the excess of the purchase price of common shares over their average carrying value.

Stock Options

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

	Year Ended Dec 31, 2012	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of year	**73,486**	**$ 34.85**
Granted [(1)]	**14,779**	**$ 29.27**
Surrendered for cash settlement	**(998)**	**$ 29.82**
Exercised for common shares	**(6,625)**	**$ 29.19**
Forfeited [(1)]	**(6,895)**	**$ 36.68**
Outstanding – end of year	**73,747**	**$ 34.13**
Exercisable – end of year	**29,366**	**$ 33.73**

(1) Subsequent to December 31, 2012, 3,479,000 stock options at a weighted average exercise price of $28.74 were granted and 8,228,000 stock options at a weighted average exercise price of $35.27 were forfeited.

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

10. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Dec 31 2012	Dec 31 2011
Derivative financial instruments designated as cash flow hedges	**$ 86**	$ 62
Foreign currency translation adjustment	**(28)**	(36)
	$ 58	$ 26

11. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% 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, 2012, the ratio was within the target range at 26%.

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

	Dec 31 2012	Dec 31 2011
Long-term debt (1)	**$ 8,736**	$ 8,571
Total shareholders' equity	**$ 24,283**	$ 22,898
Debt to book capitalization	**26%**	27%

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

12. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Weighted average common shares outstanding – basic (thousands of shares)	**1,093,925**	1,095,072	**1,097,084**	1,095,582
Effect of dilutive stock options (thousands of shares)	**1,604**	4,390	**2,435**	7,000
Weighted average common shares outstanding – diluted (thousands of shares)	**1,095,529**	1,099,462	**1,099,519**	1,102,582
Net earnings	**$ 352**	$ 832	**$ 1,892**	$ 2,643
Net earnings per common share – basic	**$ 0.32**	$ 0.76	**$ 1.72**	$ 2.41
– diluted	**$ 0.32**	$ 0.76	**$ 1.72**	$ 2.40

13. FINANCIAL INSTRUMENTS

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

	Dec 31, 2012				
Asset (liability)	**Loans and receivables at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,197**	**$ –**	**$ –**	**$ –**	**$ 1,197**
Accounts payable	**–**	**–**	**–**	**(465)**	**(465)**
Accrued liabilities	**–**	**–**	**–**	**(2,273)**	**(2,273)**
Other long-term liabilities	**–**	**4**	**(261)**	**(79)**	**(336)**
Long-term debt [(1)]	**–**	**–**	**–**	**(8,736)**	**(8,736)**
	$ 1,197	**$ 4**	**$ (261)**	**$ (11,553)**	**$ (10,613)**

	Dec 31, 2011				
Asset (liability)	Loans and receivables at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 2,077	$ –	$ –	$ –	$ 2,077
Accounts payable	–	–	–	(526)	(526)
Accrued liabilities	–	–	–	(2,347)	(2,347)
Other long-term liabilities	–	(38)	(236)	(75)	(349)
Long-term debt [(1)]	–	–	–	(8,571)	(8,571)
	$ 2,077	$ (38)	$ (236)	$ (11,519)	$ (9,716)

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

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

	Dec 31, 2012		
	Carrying amount	**Fair value**	
Asset (liability) (1)		**Level 1**	**Level 2**
Other long-term liabilities	**$ (257)**	**$ –**	**$ (257)**
Fixed rate long-term debt (2) (3) (4)	**(7,765)**	**(9,118)**	**–**
	$ (8,022)	**$ (9,118)**	**$ (257)**

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

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

(2) The carrying amount of US$350 million of 4.90% unsecured notes due December 2014 was adjusted by $19 million to reflect the fair value impact of hedge accounting. At December 31, 2011, the carrying amounts of US$350 million of 5.45% unsecured notes due October 2012 and US$350 million of 4.90% unsecured notes due December 2014 were adjusted by $31 million to reflect the fair value impact of hedge accounting.

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

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

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

Asset (liability)	**Dec 31, 2012**	Dec 31, 2011
Derivatives held for trading		
Crude oil price collars	**$ (16)**	$ (13)
Foreign currency forward contracts	**20**	(25)
Cash flow hedges		
Cross currency swaps	**(261)**	(236)
	$ (257)	$ (274)
Included within:		
Current portion of other long-term liabilities	**$ (4)**	$ (43)
Other long-term liabilities	**(253)**	(231)
	$ (257)	$ (274)

During 2012, the Company recognized a gain of $1 million (December 31, 2011 – loss of $2 million) related to ineffectiveness arising from cash flow hedges.

Risk Management

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

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

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

Asset (liability)	**Year Ended Dec 31, 2012**	Year Ended Dec 31, 2011
Balance – beginning of year	**$ (274)**	$ (485)
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**42**	128
Foreign exchange	**(53)**	42
Other comprehensive income	**28**	41
Balance – end of year	**(257)**	(274)
Less: current portion	**(4)**	(43)
	$ (253)	$ (231)

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

	Three Months Ended		Year Ended	
	Dec 31 2012	Dec 31 2011	**Dec 31 2012**	Dec 31 2011
Net realized risk management (gain) loss	**$ (8)**	$ 20	**$ 162**	$ 101
Net unrealized risk management loss (gain)	**8**	58	**(42)**	(128)
	$ –	$ 78	**$ 120**	$ (27)

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

Sales contracts

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars [(1)]	Jan 2013	–	Jun 2013	50,000 bbl/d	US$80.00	–	US$145.07	Brent
	Jan 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$135.59	Brent
	Jan 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$97.73	WTI
	Jan 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$110.34	WTI

(1) Subsequent to December 31, 2012, the Company entered into an additional 50,000 bbl/d of US$80 – US$111.05 WTI collars for the period April to December 2013 and an additional 50,000 bbl/d of US$80 – US$132.18 Brent collars for the period July to December 2013.

During the fourth quarter of 2012, US$19 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. At December 31, 2012, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At December 31, 2012, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Jan 2013	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2013	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2013	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2013	–	Mar 2038	US$550	1.170	6.25%	5.76%

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

In addition to the cross currency swap contracts noted above, at December 31, 2012, the Company had US$2,821 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, 2012, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2012, the Company had net risk management assets of $18 million with specific counterparties related to derivative financial instruments (December 31, 2011 – $nil).

c) Liquidity Risk

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

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

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 465	$ –	$ –	$ –
Accrued liabilities	$ 2,273	$ –	$ –	$ –
Risk management	$ 4	$ 53	$ 123	$ 77
Other long-term liabilities	$ 22	$ 24	$ 33	$ –
Long-term debt (1)	$ 798	$ 846	$ 2,714	$ 4,430

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

14. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2013	2014	2015	2016	2017	Thereafter
Product transportation and pipeline	$ 231	$ 218	$ 204	$ 135	$ 117	$ 788
Offshore equipment operating leases and offshore drilling	$ 156	$ 135	$ 104	$ 76	$ 57	$ 65
Office leases	$ 33	$ 34	$ 32	$ 33	$ 35	$ 262
Other	$ 173	$ 95	$ 43	$ 10	$ 2	$ 7

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

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

15. SEGMENTED INFORMATION

	Exploration and Production															
	North America				North Sea				Offshore Africa				Total Exploration and Production			
(millions of Canadian dollars, unaudited)	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	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011
Segmented product sales	**3,006**	3,163	**11,607**	11,806	**215**	317	**928**	1,224	**158**	308	**773**	946	**3,379**	3,788	**13,308**	13,976
Less: royalties	**(277)**	(482)	**(1,268)**	(1,538)	**–**	(1)	**(2)**	(3)	**(53)**	(46)	**(199)**	(114)	**(330)**	(529)	**(1,469)**	(1,655)
Segmented revenue	**2,729**	2,681	**10,339**	10,268	**215**	316	**926**	1,221	**105**	262	**574**	832	**3,049**	3,259	**11,839**	12,321
Segmented expenses																
Production	**557**	516	**2,165**	1,933	**100**	103	**402**	412	**39**	66	**163**	186	**696**	685	**2,730**	2,531
Transportation and blending	**735**	575	**2,735**	2,301	**2**	3	**10**	13	**–**	–	**1**	1	**737**	578	**2,746**	2,315
Depletion, depreciation and amortization (note 3)	**965**	726	**3,413**	2,840	**74**	65	**296**	249	**58**	72	**165**	242	**1,097**	863	**3,874**	3,331
Asset retirement obligation accretion	**21**	17	**85**	70	**7**	9	**27**	33	**2**	2	**7**	7	**30**	28	**119**	110
Realized risk management activities	**(8)**	20	**162**	101	**–**	–	**–**	–	**–**	–	**–**	–	**(8)**	20	**162**	101
Horizon asset impairment provision	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Insurance recovery – property damage (note 7)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Insurance recovery – business interruption (note 7)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Equity loss from jointly controlled entity	–	–	–	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**2,270**	1,854	**8,560**	7,245	**183**	180	**735**	707	**99**	140	**336**	436	**2,552**	2,174	**9,631**	8,388
Segmented earnings (loss) before the following	**459**	827	**1,779**	3,023	**32**	136	**191**	514	**6**	122	**238**	396	**497**	1,085	**2,208**	3,933
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing costs																
Unrealized risk management activities																
Foreign exchange loss (gain)																
Total non-segmented expenses																
Earnings before taxes																
Current income tax expense																
Deferred income tax (recovery) expense																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				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	
	2012	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011
Segmented product sales	**675**	1,005	**2,871**	1,521	**26**	22	**93**	88	**(21)**	(27)	**(77)**	(78)	**4,059**	4,788	**16,195**	15,507
Less: royalties	**(29)**	(41)	**(137)**	(60)	**–**	–	**–**	–	**–**	–	**–**	–	**(359)**	(570)	**(1,606)**	(1,715)
Segmented revenue	**646**	964	**2,734**	1,461	**26**	22	**93**	88	**(21)**	(27)	**(77)**	(78)	**3,700**	4,218	**14,589**	13,792
Segmented expenses																
Production	**372**	344	**1,504**	1,127	**8**	7	**29**	26	**(4)**	(2)	**(14)**	(13)	**1,072**	1,034	**4,249**	3,671
Transportation and blending	**15**	16	**61**	62	**–**	–	**–**	–	**(14)**	(12)	**(55)**	(50)	**738**	582	**2,752**	2,327
Depletion, depreciation and amortization (note 3)	**114**	133	**447**	266	**2**	2	**7**	7	**–**	–	**–**	–	**1,213**	998	**4,328**	3,604
Asset retirement obligation accretion	**8**	5	**32**	20	**–**	–	**–**	–	**–**	–	**–**	–	**38**	33	**151**	130
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(8)**	20	**162**	101
Horizon asset impairment provision	**–**	–	**–**	396	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	396
Insurance recovery – property damage (note 7)	**–**	3	**–**	(393)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	3	**–**	(393)
Insurance recovery – business interruption (note 7)	**–**	(16)	**–**	(333)	**–**	–	**–**	–	**–**	–	**–**	–	**–**	(16)	**–**	(333)
Equity loss from jointly controlled entity	**–**	–	**–**	–	**3**	–	**9**	–	**–**	–	**–**	–	**3**	–	**9**	–
Total segmented expenses	**509**	485	**2,044**	1,145	**13**	9	**45**	33	**(18)**	(14)	**(69)**	(63)	**3,056**	2,654	**11,651**	9,503
Segmented earnings (loss) before the following	**137**	479	**690**	316	**13**	13	**48**	55	**(3)**	(13)	**(8)**	(15)	**644**	1,564	**2,938**	4,289
Non-segmented expenses																
Administration													**64**	47	**270**	235
Share-based compensation													**(41)**	207	**(214)**	(102)
Interest and other financing costs													**83**	83	**364**	373
Unrealized risk management activities													**8**	58	**(42)**	(128)
Foreign exchange loss (gain)													**58**	(106)	**(49)**	1
Total non-segmented expenses													**172**	289	**329**	379
Earnings before taxes													**472**	1,275	**2,609**	3,910
Current income tax expense													**189**	299	**747**	860
Deferred income tax (recovery) expense													**(69)**	144	**(30)**	407
Net earnings													**352**	832	**1,892**	2,643

Capital Expenditures (1)

	Year Ended					
	Dec 31, 2012			Dec 31, 2011		
	Net expenditures	**Non cash and fair value changes(2)**	**Capitalized costs**	Net expenditures	Non cash and fair value changes(2)	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ 295**	**$ (173)**	**$ 122**	$ 309	$ (233)	$ 76
North Sea	**–**	**–**	**–**	1	(6)	(5)
Offshore Africa	**14**	**–**	**14**	2	–	2
	$ 309	**$ (173)**	**$ 136**	$ 312	$ (239)	$ 73
Property, plant and equipment						
Exploration and Production						
North America	**$ 3,831**	**$ 373**	**$ 4,204**	$ 4,427	$ 832	$ 5,259
North Sea	**254**	**263**	**517**	226	15	241
Offshore Africa	**50**	**17**	**67**	31	16	47
	4,135	**653**	**4,788**	4,684	863	5,547
Oil Sands Mining and Upgrading (3) (4)	**1,610**	**142**	**1,752**	1,182	(140)	1,042
Midstream	**14**	**–**	**14**	5	2	7
Head office	**36**	**–**	**36**	18	–	18
	$ 5,795	**$ 795**	**$ 6,590**	$ 5,889	$ 725	$ 6,614

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.

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

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

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

Segmented Assets

	Total Assets	
	Dec 31 2012	Dec 31 2011
Exploration and Production		
North America	**$ 29,012**	$ 28,233
North Sea	**1,993**	1,809
Offshore Africa	**924**	1,070
Other	**36**	23
Oil Sands Mining and Upgrading	**16,291**	15,433
Midstream	**636**	642
Head office	**88**	68
	$ 48,980	$ 47,278

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated October 2011. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended December 31, 2012:

Interest coverage (times)	
Net earnings (1)	6.4x
Cash flow from operations (2)	15.3x

(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 7, 2013. The North American conference call number is 1-877-240-9772 and the outside North American conference call number is 001-416-340-8527. Please call in about 10 minutes before the starting time in order to be patched into the call.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Thursday, March 14, 2013. 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 6854115.

WEBCAST

The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural website at www.cnrl.com.

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