FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2013 | TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2013 FIRST QUARTER RESULTS

Commenting on first quarter results, Steve Laut, President of Canadian Natural stated, "Overall this has been an excellent start to the year for Canadian Natural. Operationally it was a successful quarter, with record quarterly production of approximately 681,000 barrels of oil equivalent per day nearing the top end of our guidance and driven by record liquids production of approximately 489,000 barrels per day.

Primary heavy crude oil had record quarterly production volumes of approximately 133,000 barrels of crude oil per day as a result of a focused heavy crude oil drilling program. This is the ninth consecutive quarter of record heavy crude oil production, keeping us on track for our targeted 13% heavy crude oil production growth in 2013. Additionally, natural gas, thermal in situ bitumen, Pelican Lake heavy crude oil, Horizon SCO, light crude oil and NGLs production volumes all delivered as expected.

Canadian Natural’s thermal in situ oil sands projects had monthly average production in January of approximately 127,600 barrels of bitumen per day before entering the steam cycle in February. Our 40,000 barrels per day Kirby South Phase 1 thermal in situ oil sands project is on cost and ahead of schedule with first steam-in now targeted for the third quarter of 2013, ahead of our original plan of November 2013.

Our Horizon project achieved strong, reliable production volumes in the first quarter of 2013, averaging approximately 109,000 barrels per day, with April 2013 averaging approximately 104,000 barrels per day. Horizon has seen steady production volumes and sustained increases in reliability over the last year as we focus on an enhanced maintenance strategy and operational discipline. Reliability is expected to further increase as we move through the year with a step change in production performance after our first major turnaround. The turnaround commenced April 30, 2013 and is scheduled for 24 days.

Our Company remains well balanced with a large resource base, strong technical expertise and significant financial resources. The prudent development of these diverse assets will enable us to continue to deliver premium value and defined growth. We continue to execute on our strategy of focusing on projects which maximize returns to our shareholders in the near-, mid- and long-term."

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “Canadian Natural has a balanced portfolio of high quality assets and our cash flow remains robust which helps us deliver value to our shareholders in any commodity price cycle. As we anticipated, the industry saw a tightening of both heavy crude oil differentials and Brent-WTI differentials after the first quarter of 2013, which is resulting in more favorable price realizations for Canadian Natural.

Returning funds to the Company’s shareholders is an important part of our balanced approach to capital allocation along with continued production growth and development of our high quality, long life assets. Dividends have grown for 13 consecutive years and, when combined with share repurchases, represent a 38% compound annual growth rate in funds returned to shareholders since 2008. In 2013, year to date, we have purchased 2,965,700 common shares under the Normal Course Issuer Bid at a weighted average price of $32.12 per common share.”

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended Mar 31 2013	Dec 31 2012	Mar 31 2012
Net earnings	**$ 213**	$ 352	$ 427
Per common share – basic	**$ 0.19**	$ 0.32	$ 0.39
– diluted	**$ 0.19**	$ 0.32	$ 0.39
Adjusted net earnings from operations (1)	**$ 401**	$ 359	$ 300
Per common share – basic	**$ 0.37**	$ 0.33	$ 0.27
– diluted	**$ 0.37**	$ 0.33	$ 0.27
Cash flow from operations (2)	**$ 1,571**	$ 1,548	$ 1,280
Per common share – basic	**$ 1.44**	$ 1.41	$ 1.16
– diluted	**$ 1.44**	$ 1.41	$ 1.16
Capital expenditures, net of dispositions	**$ 1,736**	$ 1,767	$ 1,596
Daily production, before royalties			
Natural gas (MMcf/d)	**1,150**	1,134	1,302
Crude oil and NGLs (bbl/d)	**489,157**	469,964	395,461
Equivalent production (BOE/d) (3)	**680,844**	658,973	612,279

(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.

- Canadian Natural generated cash flow from operations of approximately $1.57 billion in Q1/13 compared to approximately $1.28 billion in Q1/12 and $1.55 billion in Q4/12. The increase in cash flow from the Q4/12 reflects higher synthetic crude oil ("SCO") sales volumes in the Oil Sands Mining and Upgrading segment offset by lower netbacks from the Exploration and Production segment. Adjusted net earnings from operations in Q1/13 increased to $401 million compared to $300 million in Q1/12 and $359 million in Q4/12. Changes in adjusted net earnings primarily reflect the changes in cash flow from operations.
- Total production for Q1/13 averaged 680,844 BOE/d up 11% and 3% from Q1/12 and Q4/12 levels respectively, and crude oil and NGLs production averaged 489,157 bbl/d in Q1/13, up 24% and 4% from Q1/12 and Q4/12 levels respectively, both representing quarterly production records for the Company.
- The increase in total production over the previous quarter reflects the positive results of a disciplined execution strategy driven by strong performance across the asset base, with:
  - record primary heavy crude oil production;
  - increased production from Horizon SCO, Pelican Lake heavy crude oil, light crude oil and NGLs, and natural gas; and
  - strong thermal in situ bitumen production.
- In Q1/13, primary heavy crude oil operations achieved record quarterly production of approximately 133,000 bbl/d. Primary heavy crude oil production is up 11% and 2% from Q1/12 and Q4/12 respectively. This record quarterly production will contribute to the annual primary heavy crude oil production growth which is projected to increase 13% from 2012 levels. Canadian Natural drilled 226 net primary heavy crude oil wells in Q1/13, 39 of which were in Woodenhouse. The Company is targeting to drill a total of 890 net primary heavy crude oil wells in 2013.

- In Q1/13, Pelican Lake reservoir performance continued to be very positive, as expected, with production averaging over 38,000 bbl/d on a restricted basis. The Company targets to complete construction of a new battery at Pelican Lake in June 2013, which will alleviate current production 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 heavy crude oil remains unchanged and is targeted to range from 46,000 bbl/d to 50,000 bbl/d.
- Q1/13 thermal in situ oil sands production volumes averaged approximately 109,000 bbl/d. With increased drilling and operational efficiencies the production fluctuations between the peak and the trough of the thermal in situ production cycles are narrowing. The Company targets Q2/13 thermal in situ production to range between 92,000 to 100,000 bbl/d of bitumen.
- Canadian Natural's Primrose thermal in situ property generates returns amongst the highest in the Company's portfolio. All-in operating costs are below $11.00/bbl and capital costs to grow production volumes through pad adds are approximately $13,000/bbl/d. The Company targets to drill 100 to 120 wells per year at Primrose, which will allow Canadian Natural to maintain production levels in the range of 120,000 bbl/d to 125,000 bbl/d for a period of 5 to 10 years. Engineering studies are being undertaken in 2013 to evaluate the expansion of the Primrose facilities to accelerate the development of these highly cost-effective pad additions. Annual thermal bitumen production at Primrose is targeted to grow by 5% in 2013 over 2012 levels.
- Kirby South Phase 1, the next step in the Company's well defined thermal growth plan, is on budget and ahead of schedule with first steam-in now targeted for Q3/13, ahead of the originally scheduled steam-in date of November 2013. Production is targeted to grow to 40,000 bbl/d through 2014.
- Horizon SCO production averaged approximately 109,000 bbl/d in Q1/13, an increase of 136% from Q1/12 and 31% from Q4/12 levels. April 2013 production averaged approximately 104,000 bbl/d. Safe, steady, and reliable operations continue to be a priority at Horizon. Annual SCO production is targeted to range from 100,000 bbl/d to 108,000 bbl/d in 2013 including the production impact of the planned 24 day turnaround now underway at Horizon. Completion of the turnaround should result in increased reliability and consistent production going forward at Horizon.
- The staged expansion to 250,000 bbl/d of SCO production capacity at Horizon continues to be successful as construction costs to date continue at or below cost estimates. The Horizon expansion continues to deliver capital efficiencies as we maintain a flexible schedule and execution strategy.
- At Septimus, the Company's liquids rich natural gas Montney play, drilling and facility expansion is ahead of schedule and on budget. Upon completion of the facility expansion in Q3/13, natural gas sales levels from Septimus are targeted to increase to 125 MMcf/d, yielding 12,200 bbl/d of liquids up from current levels of approximately 60 MMcf/d and approximately 5,600 bbl/d of liquids.
- Canadian Natural purchased 965,700 common shares during the quarter for cancellation at a weighted average price of $32.72 per common share. Subsequent to March 31, 2013, the Company purchased an additional 2,000,000 common shares at a weighted average price of $31.83 per common share.
- 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, which exceeded 11,000,000 shares.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.125 per share payable on July 1, 2013, up 19% from the dividend paid at the same time in 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

Drilling activity (number of wells)

	Three Months Ended Mar 31			
	2013		2012	
	Gross	**Net**	Gross	Net
Crude oil	**312**	**300**	300	278
Natural gas	**18**	**15**	21	19
Dry	**6**	**5**	6	6
Subtotal	**336**	**320**	327	303
Stratigraphic test / service wells	**305**	**305**	584	584
Total	**641**	**625**	911	887
Success rate (excluding stratigraphic test / service wells)		**98%**		98%

North America Exploration and Production

Crude Oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Crude oil and NGLs production (bbl/d)	**236,600**	230,621	225,286
Net wells targeting crude oil	**271**	275	241
Net successful wells drilled	**267**	256	235
Success rate	**99%**	93%	98%

- North America crude oil and NGLs production averaged 236,600 bbl/d in Q1/13, an increase of 5% and 3% from Q1/12 and Q4/12 levels respectively.
- Canadian Natural drilled 226 net primary heavy crude oil wells in Q1/13, 39 of which were located in the Woodenhouse area outside of the traditional primary heavy crude oil fairway. Canadian Natural’s primary heavy crude oil continues to provide strong netbacks and the highest return on capital in the Company’s portfolio of diverse and balanced assets. In Q1/13 primary heavy crude oil operations achieved record production volumes of approximately 133,000 bbl/d, resulting in the ninth consecutive quarter of record primary heavy crude oil production volumes, contributing to the targeted 13% primary heavy crude oil production growth in 2013. Another 115 net primary heavy crude oil wells are planned for Q2/13.

- During Q1/13, Pelican Lake reservoir performance remained strong. Facility optimizations allowed the Company to access excess production capacity, enabling total production to exceed 38,000 bbl/d. Recent production volumes at Pelican Lake have been restricted due to facility constraints. In addition, production volumes from the primary heavy crude oil area of Woodenhouse were also restricted by such facility constraints as they utilize Pelican Lake processing facilities. Construction of the new battery at Pelican Lake, on track for completion in June 2013, will alleviate facility constraints and enable a step increase in Pelican Lake and Woodenhouse production volumes through the second half of 2013.
- North America light crude oil and NGLs Q1/13 production increased 2% from Q4/12 as this year's drilling program commenced. 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.
- Planned drilling activity for Q2/13 includes 127 net crude oil wells, excluding stratigraphic ("strat") and service wells.

Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Bitumen production (bbl/d)	**108,889**	121,362	80,327
Net wells targeting bitumen	**33**	38	43
Net successful wells drilled	**33**	38	43
Success rate	**100%**	100%	100%

- Q1/13 thermal in situ oil sands production volumes averaged approximately 109,000 bbl/d. Due to steaming and production cycles, production is targeted to range between 92,000 and 100,000 bbl/d in Q2/13, and subsequently increase in Q3/13. Canadian Natural targets to increase 2013 thermal in situ production by 5% over 2012 levels, continuing to operate effectively and efficiently, while maintaining industry leading operating costs.
  - Canadian Natural's Primrose property generates returns amongst the highest in the Company's portfolio. All-in operating costs are below $11.00/bbl and capital costs to grow production volumes through pad adds are approximately $13,000/bbl/d. The Company targets to drill 100 to 120 wells per year at Primrose, which will allow Canadian Natural to maintain production levels at Primrose in the range of 120,000 bbl/d to 125,000 bbl/d for a period of 5 to 10 years. Engineering studies are being undertaken in 2013 to evaluate the expansion of the Primrose facilities to accelerate the development of these highly cost-effective pad additions.
  - Kirby South Phase 1 to date remains ahead of plan and on budget. Drilling is on track to complete the seventh and final pad in Q2/13. Focus will shift from construction to commissioning in late Q2/13 with first steam-in now targeted for Q3/13, ahead of the originally scheduled steam-in date of November 2013. Production is targeted to grow to 40,000 bbl/d through 2014.
  - Detailed engineering is progressing for Kirby North Phase 1. As of March 31, 2013, the engineering portion was 45% complete. Construction of the main access road has been completed and site preparation will continue into Q3/13. A drilling program, consisting of 45 strat and 5 observation wells, was completed during Q1/13, confirming resource delineation and pad layouts for Kirby North Phase 1. The full project will be submitted for Board sanctioning in Q3/13, with first steam-in targeted for 2016 and targeted ultimate production levels of 40,000 bbl/d.
  - Kirby South Phase 1 and Kirby North Phase 1 contribute to a targeted total staged expansion of production volumes from the greater Kirby area over time to 140,000 bbl/d, with the overall thermal in situ development plan targeted to increase to 510,000 bbl/d of production capacity.
- Planned drilling activity for Q2/13 includes 27 net thermal in situ wells, excluding strat and service wells.

Natural Gas

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Natural gas production (MMcf/d)	**1,125**	1,113	1,281
Net wells targeting natural gas	**16**	3	19
Net successful wells drilled	**15**	3	19
Success rate	**94%**	100%	100%

- During Q1/13, North American natural gas production averaged 1,125 MMcf/d, representing a 12% decrease from Q1/12 levels and a 1% increase from Q4/12 levels. The decrease in production levels year over year was due to expected production declines, reflecting Canadian Natural's strategic decision to allocate capital to higher return crude oil projects. The increase quarter over quarter reflects the resumption of natural gas production volumes as a result of reduced third party facility constraints in Northeast British Columbia, and from minor acquisitions.
- At Septimus, the Company's liquids rich natural gas Montney play, drilling and plant expansion is ahead of schedule and on budget. Canadian Natural drilled 8 net wells in Septimus during Q1/13, and targets to drill 5 more wells in Q2/13. To date, the expansion is on track with first production targeted for July 2013, adding 22 MMcf/d of natural gas sales, bringing total production to 79 MMcf/d of natural gas sales and 7,700 bbl/d of liquids. Production will ultimately grow by August 2013 to the plant expansion capacity of 125 MMcf/d of natural gas sales, yielding 12,200 bbl/d of liquids, up from current levels of approximately 60 MMcf/d and approximately 5,600 bbl/d of liquids, following processing through the plant and deep cut facilities.
- Canadian Natural has a dominant Montney land position with over one million high quality net acres, the largest in the industry. In Q1/13 the Company commenced the process to monetize approximately 250,000 net acres (approximately 390 net sections) of its Montney land base in the liquids rich fairway in the Graham Kobes area of Northeast British Columbia. To maximize the value of this important asset 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 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 Northwest Alberta.

International Exploration and Production

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Crude oil production (bbl/d)			
North Sea	**18,774**	19,140	23,046
Offshore Africa	**16,112**	15,762	20,712
Natural gas production (MMcf/d)			
North Sea	**1**	1	3
Offshore Africa	**24**	20	18
Net wells targeting crude oil	–	–	–
Net successful wells drilled	–	–	–
Success rate	–	–	–

- International crude oil production averaged 34,886 bbl/d during the quarter, which was in line with Q4/12 production and at the high end of the Company's previously stated guidance of 31,000 to 35,000 bbl/d. Crude oil production volumes declined 20% from Q1/12 as a result of natural field declines and the cessation of North Sea drilling activity following an increase in the Supplementary Charge Tax Rate in 2011.

- In September 2012, the UK government announced the implementation of the Brownfield Allowance ("BFA"), which allows for a property development allowance on qualifying preapproved field developments. This allowance partially mitigates the impact of previous tax increases. In Q1/13, the Company received approval for a BFA for its Tiffany field development and as a result, Canadian Natural has commenced infill drilling and targets first oil production from this program in Q2/13.
- A further BFA application for a Ninian field development has been submitted, with approval anticipated in Q2/13. If the Ninian BFA and future BFA applications are approved as expected, additional drilling can be undertaken in the North Sea to increase production and lower current operating costs and reverse the declines seen in the UK since the increase in the Supplementary Charge Tax Rate.
- The light crude oil infill drilling program at Espoir, Offshore Africa, originally targeted to commence in late Q2/13, is progressing slower than anticipated due to contractor safety and performance concerns. The Company is actively engaged with the contractor to ensure the drilling program will be conducted safely and efficiently.
- Regarding Canadian Natural's prospective offshore South Africa property, a partner has been selected to jointly conduct exploratory drilling on the property. The Company will provide further details on the partnership terms upon receipt of regulatory approval. Targeted drilling windows are from Q4/13 to Q1/14 and from Q4/14 to Q1/15 and the necessary long-lead equipment has been ordered.
- Exploration work on Block 514 in Côte d'Ivoire, in which Canadian Natural has a 36% working interest, is underway and a seismic program has been completed. The Company believes this block is prospective for deepwater channel/fan structures similar to the Jubilee crude oil discoveries in Ghana and plays elsewhere in offshore Africa.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Synthetic crude oil production (bbl/d)	**108,782**	83,079	46,090

- During Q1/13 Horizon Oil Sands achieved average SCO production of approximately 109,000 bbl/d. Production volumes were 136% higher than Q1/12 levels and 31% higher than the previous quarter as the reliability of the Horizon plant steadily improved as a result of safe, steady, and reliable operations. Horizon production in April averaged approximately 104,000 bbl/d of SCO.
- The first major maintenance turnaround at Horizon commenced April 30, 2013 and is scheduled to last 24 days. 2013 annual guidance remains unchanged at 100,000 bbl/d to 108,000 bbl/d of SCO including the impact of the turnaround. The turnaround will include required inspections, catalyst change outs, exchanger repairs and will address maintenance items to ensure safe, steady and reliable production going forward. A step change in reliability and strong production performance is expected post turnaround.
- The Horizon Phase 2/3 expansion has unique competitive advantages when compared to other mining developments. Horizon has been designed for optimal performance at 250,000 bbl/d, where the Company can leverage prebuilt infrastructure from Phase 1. Increased reliability and redundancy will be achieved upon completion of the Phase 2/3 expansion and significantly lower operating costs will result as large portions of operating costs are fixed. These factors provide sustainable economic incentives when compared to other mining projects.
- Canadian Natural's staged expansion to 250,000 bbl/d of SCO production capacity continues to progress on track. Capital expenditures to date on Phase 2/3 expansion are at or below cost estimates as the Company executes its cost focused strategy. Expansion work at Horizon will ultimately add an additional 140,000 bbl/d of SCO production in a staged, disciplined manner. Horizon provides high quality, long life SCO production without decline for decades.
- An update to the staged Phase 2/3 expansion on an Engineering, Procurement and Construction basis at the end of Q1/13 is as follows:
    - Overall Horizon Phase 2/3 expansion is 20% complete.
    - Reliability – Tranche 2 is 88% complete. This project is targeted for completion in late 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 project remains on track and is currently 17% complete.
- Phase 2A is a coker expansion. The expansion is 52% complete, and is targeted to add 10,000 bbl/d of production capacity in 2015.
- Phase 2B is 11% 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 11% complete, and includes the addition of supplementary extraction trains. This phase is targeted to increase production capacity by 80,000 bbl/d in 2017.
- The projects which are currently under construction continue to trend at or below cost estimates.

▪ Total capital budgeted for the Horizon Phase 2/3 expansion in 2013 is $2.06 billion. Canadian Natural continues to be disciplined and cost driven in the Horizon Phase 2/3 expansion to ensure the expansion continues effectively and efficiently.

MARKETING

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Crude oil and NGLs pricing			
WTI benchmark price (US$/bbl) (1)	**$ 94.34**	$ 88.20	$ 102.94
Dated Brent benchmark price (US$/bbl)	**$ 112.43**	$ 110.03	$ 118.47
WCS blend differential from WTI (%) (2)	**34%**	21%	21%
SCO price (US$/bbl)	**$ 95.24**	$ 91.90	$ 98.11
Condensate benchmark price (US$/bbl)	**$ 107.18**	$ 98.13	$ 110.05
Average realized pricing before risk management (C$/bbl) (3)	**$ 60.87**	$ 66.55	$ 82.32
SCO realized pricing (US$/bbl)	**$ 96.19**	$ 89.40	$ 99.20
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 2.92**	$ 2.89	$ 2.39
Average realized pricing before risk management (C$/Mcf) (3)	**$ 3.51**	$ 3.42	$ 2.73

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

▪ The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During Q1/13, condensate price premiums to WTI widened, reflecting normal seasonality and overall growth in heavy crude oil diluent blending demand.

▪ Canadian Natural contributed over 178,000 bbl/d of its heavy crude oil blends to the WCS blend in Q1/13. The Company remains the largest contributor to the WCS blend, accounting for over 57% of the total blend this quarter.

▪ The WCS heavy crude oil differential ("WCS differential") as a percent of WTI averaged 34% during the quarter compared with 21% in both Q1/12 and Q4/12. The differential widened during Q1/13 was due to the seasonal reduction in the demand for heavy crude oil and as a result of planned and unplanned maintenance at refineries accessible to Canadian heavy crude oil. In April and May 2013, the WCS differential, based on current indicative pricing, narrowed to 25% and 15% respectively, in line with the Company's long term expectations.

▪ Dated Brent-WTI differentials have narrowed in Q2/13 from Q1/13 levels resulting in better overall pricing relative to Brent pricing for Canadian Natural's North American crude oil production, which is typically benchmarked to WTI.

Benchmark Pricing	WCS Blend Differential from WTI (%)	Dated Brent Differential from WTI (US$/bbl)
2013		
January	**35%**	**$ 18.18**
February	**39%**	**$ 20.96**
March	**28%**	**$ 15.41**
April	**25%**	**$ 9.85**
May*	**15%**	**$ 8.06**
June*	**19%**	**$ 8.20**

**Based on current indicative pricing as at April 30, 2013.*

- During Q4/12, 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. Additionally, the Company has committed 120,000 bbl/d on the proposed Keystone XL pipeline. This pipeline, when built, will bring Canadian heavy crude oil to the Gulf Coast where underutilized heavy oil refining capacity exists.

NORTH WEST REDWATER UPGRADING AND REFINING

In Q1/13 work continued on the North West Redwater refinery and completion is targeted for mid-2016. 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 its disciplined approach to 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 680,844 BOE/d for Q1/13 with over 97% of production located in G8 countries.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 28% and debt to EBITDA of 1.2x. At March 31, 2013, long-term debt amounted to $9.3 billion.
- In Q1/13 the Company initiated a US commercial paper program for short-term borrowing. This program will facilitate lower financing costs and provides a diversification of liquidity which further strengthens the financial stability and flexibility of the Company.
- Canadian Natural maintains significant financial stability and liquidity represented by approximately $2.4 billion, net of commercial paper issued, of available credit under its bank credit facilities.
- The Company's commodity hedging program protects investment returns, ensures ongoing balance sheet strength and supports the Company's cash flow for its capital expenditure programs. Approximately 52% of forecasted 2013 crude oil volumes are currently hedged using price collars and physical crude oil sales contracts with fixed WCS differentials. Through the use of collars, the Company has hedged 250,000 bbl/d of crude oil volumes in Q2/13 to Q4/13. To partially mitigate its exposure to widening heavy crude oil differentials, the Company has entered into physical crude oil sales contracts with weighted average fixed WCS differentials as follows: 9,300 bbl/d in Q2/13 at US$19.98/bbl; 11,000 bbl/d in the Q3/13 at US$21.04/bbl; and 8,000 bbl/d in Q4/13 at US$21.19/bbl. Details of the Company's commodity hedging program can be found on the Company's website at www.cnrl.com.
- Subsequent to Q1/13, Toronto Stock Exchange accepted notice of Canadian Natural's Normal Course Issuer Bid through facilities of Toronto Stock Exchange and the New York Stock Exchange. The notice provides that Canadian Natural may, during the 12 month period commencing April 2013 and ending April 2014, purchase for cancellation on Toronto Stock Exchange and the New York Stock Exchange up to 54,635,116 common shares.

- Canadian Natural purchased 965,700 common shares during the quarter for cancellation at a weighted average price of $32.72 per common share. Subsequent to March 31, 2013, the Company purchased an additional 2,000,000 common shares at a weighted average price of $31.83 per common share.
- 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 2012, which exceeded 11,000,000 shares.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.125 per share payable on July 1, 2013.

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. Q2/13 production guidance before royalties is forecast to average between 1,090 and 1,110 MMcf/d of natural gas and between 435,000 and 461,000 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.

This page left intentionally blank

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 ended March 31, 2013 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2012.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's consolidated financial statements for the period ended March 31, 2013 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 blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion refers primarily to the Company's financial results for the three months ended March 31, 2013 in relation to the first quarter of 2012 and the fourth 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, 2012, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated May 2, 2013.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Product sales	**$ 4,101**	$ 4,059	$ 3,971
Net earnings	**$ 213**	$ 352	$ 427
Per common share – basic	**$ 0.19**	$ 0.32	$ 0.39
– diluted	**$ 0.19**	$ 0.32	$ 0.39
Adjusted net earnings from operations (1)	**$ 401**	$ 359	$ 300
Per common share – basic	**$ 0.37**	$ 0.33	$ 0.27
– diluted	**$ 0.37**	$ 0.33	$ 0.27
Cash flow from operations (2)	**$ 1,571**	$ 1,548	$ 1,280
Per common share – basic	**$ 1.44**	$ 1.41	$ 1.16
– diluted	**$ 1.44**	$ 1.41	$ 1.16
Capital expenditures, net of dispositions	**$ 1,736**	$ 1,767	$ 1,596

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

Adjusted Net Earnings from Operations

	Three Months Ended		
($ millions)	***Mar 31 2013***	*Dec 31 2012*	*Mar 31 2012*
Net earnings as reported	***$ 213***	*$ 352*	*$ 427*
Share-based compensation, net of tax (1)	***71***	*(41)*	*(107)*
Unrealized risk management loss, net of tax (2)	***51***	*4*	*40*
Unrealized foreign exchange loss (gain), net of tax (3)	***78***	*254*	*(60)*
Realized foreign exchange gain on repayment of US dollar debt securities (4)	***(12)***	*(210)*	*–*
Adjusted net earnings from operations	***$ 401***	*$ 359*	*$ 300*

(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 first quarter of 2013, the Company repaid US$400 million of 5.15% unsecured notes. During the fourth quarter of 2012, the Company repaid US$350 million of 5.45% unsecured notes.

Cash Flow from Operations

	Three Months Ended		
($ millions)	***Mar 31 2013***	*Dec 31 2012*	*Mar 31 2012*
Net earnings	***$ 213***	*$ 352*	*$ 427*
Non-cash items:			
Depletion, depreciation and amortization	***1,142***	*1,213*	*975*
Share-based compensation	***71***	*(41)*	*(107)*
Asset retirement obligation accretion	***42***	*38*	*37*
Unrealized risk management loss	***62***	*8*	*60*
Unrealized foreign exchange loss (gain)	***78***	*254*	*(60)*
Realized foreign exchange gain on repayment of US dollar debt securities	***(12)***	*(210)*	*–*
Equity loss from jointly controlled entity	***2***	*3*	*–*
Deferred income tax recovery	***(27)***	*(69)*	*(52)*
Cash flow from operations	***$ 1,571***	*$ 1,548*	*$ 1,280*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the first quarter of 2013 were $213 million compared with $427 million for the first quarter of 2012 and $352 million for the fourth quarter of 2012. Net earnings for the first quarter of 2013 included net after-tax expenses of $188 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, and the impact of a realized foreign exchange gain on repayment of long-term debt compared with net after-tax income of $127 million for the first quarter of 2012 and net after-tax expenses of $7 million for the fourth quarter of 2012. Excluding these items, adjusted net earnings from operations for the first quarter of 2013 were $401 million compared with $300 million for the first quarter of 2012 and $359 million for the fourth quarter of 2012.

The increase in adjusted net earnings for the first quarter of 2013 from the first quarter of 2012 was primarily due to:

- higher crude oil and synthetic crude oil ("SCO") sales volumes in the North America and Oil Sands Mining and Upgrading segments;
- higher realized natural gas netbacks; and
- higher realized risk management gains;

partially offset by:

- lower crude oil and NGLs netbacks;
- lower natural gas sales volumes; and
- higher depletion, depreciation and amortization expense.

The increase in adjusted net earnings for the first quarter of 2013 from the fourth quarter of 2012 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- higher realized SCO prices;
- higher realized risk management gains;
- lower depletion, depreciation and amortization expense; and
- the impact of a weaker Canadian dollar;

partially offset by:

- lower crude oil and NGLs sales volumes and netbacks.

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

Cash flow from operations for the first quarter of 2013 was $1,571 million compared with $1,280 million for the first quarter of 2012 and $1,548 million for the fourth quarter of 2012. The increase 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 first quarter of 2013 increased 11% to 680,844 BOE/d from 612,279 BOE/d for the first quarter of 2012 and increased 3% from 658,973 BOE/d for the fourth 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)		**Mar 31 2013**		Dec 31 2012		Sep 30 2012		Jun 30 2012
Product sales	**$**	**4,101**	$	4,059	$	3,978	$	4,187
Net earnings	**$**	**213**	$	352	$	360	$	753
Net earnings per common share								
– basic	**$**	**0.19**	$	0.32	$	0.33	$	0.68
– diluted	**$**	**0.19**	$	0.32	$	0.33	$	0.68

($ millions, except per common share amounts)		Mar 31 2012		Dec 31 2011		Sep 30 2011		Jun 30 2011
Product sales	$	3,971	$	4,788	$	3,690	$	3,727
Net earnings	$	427	$	832	$	836	$	929
Net earnings per common share								
– basic	$	0.39	$	0.76	$	0.76	$	0.85
– diluted	$	0.39	$	0.76	$	0.76	$	0.84

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 reference location at Cushing, Oklahoma ("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 crude 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.
- **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 also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.

BUSINESS ENVIRONMENT

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
WTI benchmark price (US$/bbl)	**$ 94.34**	$ 88.20	$ 102.94
Dated Brent benchmark price (US$/bbl)	**$ 112.43**	$ 110.03	$ 118.47
WCS blend differential from WTI (US$/bbl)	**$ 31.79**	$ 18.15	$ 21.47
WCS blend differential from WTI (%)	**34%**	21%	21%
SCO price (US$/bbl)	**$ 95.24**	$ 91.90	$ 98.11
Condensate benchmark price (US$/bbl)	**$ 107.18**	$ 98.13	$ 110.05
NYMEX benchmark price (US$/MMBtu)	**$ 3.35**	$ 3.36	$ 2.77
AECO benchmark price (C$/GJ)	**$ 2.92**	$ 2.89	$ 2.39
US/Canadian dollar average exchange rate (US$)	**$ 0.9917**	$ 1.0088	$ 0.9989

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$94.34 per bbl for the first quarter of 2013, a decrease of 8% from US$102.94 per bbl for the first quarter of 2012, and an increase of 7% from US$88.20 per bbl for the fourth quarter of 2012. The decrease in WTI pricing for the first quarter of 2013 from the first quarter of 2012 was reflective of the European debt crisis, political instability in the Middle East and lower than expected growth in Asian demand. The increase in WTI pricing from the fourth quarter of 2012 reflected increased optimism in the United States economy as well as incremental pipeline capacity to the US Gulf Coast on the Seaway pipeline.

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$112.43 per bbl for the first quarter of 2013, a decrease of 5% from US$118.47 per bbl for the first quarter of 2012, and an increase of 2% from US$110.03 per bbl for the fourth quarter of 2012.

The WCS Heavy Differential averaged 34% for the first quarter of 2013, compared with 21% in the first and fourth quarters of 2012. The WCS Heavy Differential widened in the first quarter of 2013 from the comparable periods as a result of planned and unplanned maintenance at key refineries accessible by Canadian crude oil. The WCS Heavy Differential per barrel narrowed in April 2013 to average US$23.20 per bbl and in May 2013 to average US$13.87 per bbl. To partially mitigate its exposure to widening heavy crude oil differentials, the Company has entered into physical crude oil sales contracts with weighted average fixed WCS differentials as follows: 9,300 bbl/d in the second quarter of 2013 at US$19.98 per bbl; 11,000 bbl/d in the third quarter of 2013 at US$21.04 per bbl; and 8,000 bbl/d in the fourth quarter of 2013 at US$21.19 per bbl.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During the first quarter of 2013, condensate price premiums to WTI widened, reflecting normal seasonality and overall growth in heavy oil diluent blending demand.

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$3.35 per MMBtu for the first quarter of 2013, an increase of 21% from US$2.77 per MMBtu for the first quarter of 2012, and was comparable with the fourth quarter of 2012.

AECO natural gas prices for the first quarter of 2013 averaged $2.92 per GJ, an increase of 22% from $2.39 per GJ for the first quarter of 2012, and an increase of 1% from $2.89 per GJ for the fourth quarter of 2012.

During the first quarter of 2013, natural gas prices continued to recover from the low pricing levels in 2012. Higher utilization of gas fired electric generation, a steady North America production supply forecast and a return to normal winter weather in North America has allowed natural gas inventories to return to seasonal levels.

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		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**345,489**	351,983	305,613
North America – Oil Sands Mining and Upgrading	**108,782**	83,079	46,090
North Sea	**18,774**	19,140	23,046
Offshore Africa	**16,112**	15,762	20,712
	489,157	469,964	395,461
Natural gas (MMcf/d)			
North America	**1,125**	1,113	1,281
North Sea	**1**	1	3
Offshore Africa	**24**	20	18
	1,150	1,134	1,302
Total barrels of oil equivalent (BOE/d)	**680,844**	658,973	612,279
Product mix			
Light and medium crude oil and NGLs	**15%**	15%	18%
Pelican Lake heavy crude oil	**5%**	5%	6%
Primary heavy crude oil	**20%**	20%	20%
Bitumen (thermal oil)	**16%**	18%	13%
Synthetic crude oil	**16%**	13%	8%
Natural gas	**28%**	29%	35%
Percentage of product sales (1) (2) (excluding midstream revenue)			
Crude oil and NGLs	**89%**	90%	90%
Natural gas	**11%**	10%	10%

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

(2) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**289,992**	305,577	253,951
North America – Oil Sands Mining and Upgrading	**104,203**	79,691	43,599
North Sea	**18,706**	19,096	22,986
Offshore Africa	**13,603**	10,358	17,497
	426,504	414,722	338,033
Natural gas (MMcf/d)			
North America	**1,092**	1,047	1,277
North Sea	**1**	1	3
Offshore Africa	**20**	16	15
	1,113	1,064	1,295
Total barrels of oil equivalent (BOE/d)	**612,062**	592,080	553,752

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, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil) and SCO.

Crude oil and NGLs production for the first quarter of 2013 increased 24% to 489,157 bbl/d from 395,461 bbl/d for the first quarter of 2012 and increased 4% from 469,964 bbl/d for the fourth quarter of 2012. The increase in production for the first quarter of 2013 compared with the first quarter of 2012 was primarily due to the increase in Horizon production volumes, the impact of a strong heavy crude oil drilling program and the increased production from the Company's cyclic thermal operations. The increase in production from the fourth quarter of 2012 was primarily due to the increase in Horizon production volumes, partially offset by the decrease in production from the Company's cyclic thermal operations. The fluctuations in the Company's thermal production from quarter to quarter were due to the cyclic nature of thermal operations. Crude oil and NGLs production in the first quarter of 2013 was within the Company's previously issued guidance of 471,000 to 495,000 bbl/d.

Natural gas production for the first quarter of 2013 decreased 12% to 1,150 MMcf/d from 1,302 MMcf/d for the first quarter of 2012 and increased 1% from 1,134 MMcf/d for the fourth quarter of 2012. The decrease in natural gas production from the first quarter of 2012 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. The increase in natural gas production from the fourth quarter of 2012 reflected the resumption of production of certain natural gas volumes that were previously restricted, as well as the impact of natural gas producing properties acquired in the fourth quarter of 2012. Natural gas production in the first quarter of 2013 was at the high end of the Company's previously issued guidance of 1,130 to 1,150 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. Second quarter 2013 production guidance is targeted to average between 435,000 and 461,000 bbl/d of crude oil and NGLs and between 1,090 and 1,110 MMcf/d of natural gas.

North America – Exploration and Production

For the first quarter of 2013, crude oil and NGLs production increased 13% to average 345,489 bbl/d compared with 305,613 bbl/d for the first quarter of 2012 and decreased 2% from 351,983 bbl/d in the fourth quarter of 2012. The increase in crude oil and NGLs production from the first quarter of 2012 was primarily due to the impact of a strong heavy crude oil drilling program and the increased production from the Company's cyclic thermal operations. The decrease from the fourth quarter of 2012 was primarily due to the decrease in production from the Company's cyclic thermal operations. First quarter 2013 production of crude oil and NGLs was within the Company's previously issued guidance of 335,000 to 349,000 bbl/d. Second quarter 2013 production guidance is targeted to average between 326,000 and 342,000 bbl/d for crude oil and NGLs.

Natural gas production decreased 12% to 1,125 MMcf/d for the first quarter of 2013 compared with 1,281 MMcf/d in the first quarter of 2012 and increased 1% from 1,113 MMcf/d for the fourth quarter of 2012. The decrease in natural gas production from the first quarter of 2012 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. The increase from the fourth quarter of 2012 primarily reflected the resumption of production of certain natural gas volumes which were previously restricted, as well as the impact of natural gas producing properties acquired in the fourth quarter of 2012.

North America – Oil Sands Mining and Upgrading

For the first quarter of 2013, SCO production averaged 108,782 bbl/d compared with 46,090 bbl/d for the first quarter of 2012 and 83,079 bbl/d for the fourth quarter of 2012. First quarter production in 2013 increased from the comparable periods as a result of the Company's strong operating performance and its continued focus on efficient and effective operations. Production of SCO was within the Company's previously issued guidance of 105,000 to 111,000 bbl/d for the first quarter of 2013. Second quarter 2013 production guidance is targeted to average between 77,000 and 83,000 bbl/d due to the impact of the 24 day planned maintenance turnaround in May 2013.

North Sea

For the first quarter of 2013, North Sea crude oil production decreased 19% to 18,774 bbl/d compared with 23,046 bbl/d for the first quarter of 2012, and decreased 2% from 19,140 bbl/d in the fourth quarter of 2012. The decrease in production from the comparable periods was primarily due to natural field declines and a reduction in drilling activities as a result of an increase in the corporate income tax rate in 2011.

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 undergoing repairs. The extent of the property damage, including associated costs, is not expected to be significant.

Offshore Africa

First quarter 2013 crude oil production averaged 16,112 bbl/d, decreasing 22% from 20,712 bbl/d for the first quarter of 2012 and increasing 2% from 15,762 bbl/d in the fourth quarter of 2012. The decrease in production volumes for the first quarter of 2013 from the first quarter of 2012 was due to natural field declines and lower production from Gabon. The increase in production volumes from the fourth quarter of 2012 was due to the completion of planned turnaround activity at Espoir during the fourth quarter of 2012, partially offset by natural field declines. Late in the first quarter of 2013, the midwater arch at the Olowi field in Gabon was stabilized and production was reinstated. The Company is currently assessing the long-term operability of the midwater arch.

International Guidance

The Company's North Sea and Offshore Africa first quarter 2013 crude oil and NGLs production was within the Company's previously issued guidance of 31,000 to 35,000 bbl/d. Second quarter 2013 production guidance is targeted to average between 32,000 and 36,000 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 FPSOs, as follows:

(bbl)	**Mar 31 2013**	Dec 31 2012	Mar 31 2012
North America – Exploration and Production	**811,181**	643,758	621,277
North America – Oil Sands Mining and Upgrading (SCO)	**1,334,054**	993,627	1,053,025
North Sea	**409,333**	77,018	84,112
Offshore Africa	**829,793**	1,036,509	853,074
	3,384,361	2,750,912	2,611,488

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Crude oil and NGLs ($/bbl) [1]			
Sales price [2] [3]	**$ 60.87**	$ 66.55	$ 82.32
Transportation	**2.37**	2.32	2.24
Realized sales price, net of transportation	**58.50**	64.23	80.08
Royalties	**8.76**	8.59	13.08
Production expense	**17.56**	15.32	16.78
Netback	**$ 32.18**	$ 40.32	$ 50.22
Natural gas ($/Mcf) [1]			
Sales price [2] [3]	**$ 3.51**	$ 3.42	$ 2.73
Transportation	**0.29**	0.26	0.26
Realized sales price, net of transportation	**3.22**	3.16	2.47
Royalties	**0.12**	0.21	0.05
Production expense	**1.53**	1.43	1.34
Netback	**$ 1.57**	$ 1.52	$ 1.08
Barrels of oil equivalent ($/BOE) [1]			
Sales price [2] [3]	**$ 47.90**	$ 51.97	$ 57.26
Transportation	**2.21**	2.14	2.05
Realized sales price, net of transportation	**45.69**	49.83	55.21
Royalties	**6.05**	6.22	8.23
Production expense	**14.74**	13.11	13.43
Netback	**$ 24.90**	$ 30.50	$ 33.55

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Crude oil and NGLs ($/bbl) (1) (2) (3)			
North America	**$ 55.68**	$ 62.68	$ 76.72
North Sea	**$ 114.28**	$ 109.47	$ 118.26
Offshore Africa	**$ 113.70**	$ 97.97	$ 128.94
Company average	**$ 60.87**	$ 66.55	$ 82.32
Natural gas ($/Mcf) (1) (2) (3)			
North America	**$ 3.37**	$ 3.30	$ 2.62
North Sea	**$ 3.65**	$ 3.96	$ 5.07
Offshore Africa	**$ 10.24**	$ 10.39	$ 10.00
Company average	**$ 3.51**	$ 3.42	$ 2.73
Company average ($/BOE) (1) (2) (3)	**$ 47.90**	$ 51.97	$ 57.26

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

North America

North America realized crude oil prices averaged $55.68 per bbl for the first quarter of 2013, a decrease of 27% compared with $76.72 per bbl for the first quarter of 2012 and a decrease of 11% compared with $62.68 per bbl for the fourth quarter of 2012. The decrease in realized crude oil prices for the first quarter of 2013 from the comparable periods was due to the widening of the WCS Heavy Differential and higher diluent blending costs; partially offset by the impact of a weaker Canadian dollar relative to the US dollar as well as fluctuations in WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2013 contributed approximately 178,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 29% to average $3.37 per Mcf for the first quarter of 2013 compared with $2.62 per Mcf in the first quarter of 2012, and increased 2% compared with $3.30 per Mcf for the fourth quarter of 2012. The increase in realized natural gas prices for the first quarter of 2013 from the comparable periods was primarily due to higher AECO benchmark pricing related to the impact of higher utilization of gas fired electric generation, a steady North America production supply forecast and a return to normal winter weather in North America.

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

(Quarterly Average)		**Mar 31 2013**		Dec 31 2012		Mar 31 2012
Wellhead Price (1) (2) (3)						
Light and medium crude oil and NGLs ($/bbl)	**$**	**73.77**	$	70.20	$	78.01
Pelican Lake heavy crude oil ($/bbl)	**$**	**54.41**	$	65.12	$	77.82
Primary heavy crude oil ($/bbl)	**$**	**51.45**	$	62.02	$	75.28
Bitumen (thermal oil) ($/bbl)	**$**	**50.42**	$	58.69	$	77.28
Natural gas ($/Mcf)	**$**	**3.37**	$	3.30	$	2.62

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.
(3) Comparative figures have been adjusted to reflect realized product prices before transportation costs.

North Sea

North Sea realized crude oil prices averaged $114.28 per bbl for the first quarter of 2013, a decrease of 3% from $118.26 per bbl for the first quarter of 2012, and an increase of 4% from $109.47 per bbl for the fourth quarter of 2012. The fluctuations in realized crude oil prices for the first quarter of 2013 from the comparable periods were primarily the result of the fluctuations in the Brent benchmark pricing, the weakening of the Canadian dollar, and the timing of liftings.

Offshore Africa

Offshore Africa realized crude oil prices decreased 12% to average $113.70 per bbl for the first quarter of 2013 from $128.94 per bbl for the first quarter of 2012, and increased 16% from $97.97 per bbl for the fourth quarter of 2012. The fluctuations in realized crude oil prices for the first quarter of 2013 from the comparable periods were primarily the result of the fluctuations in the Brent benchmark pricing, the weakening of the Canadian dollar, and the timing of liftings.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 8.65**	$ 7.93	$ 13.75
North Sea	**$ 0.41**	$ 0.25	$ 0.30
Offshore Africa	**$ 17.71**	$ 33.59	$ 20.01
Company average	**$ 8.76**	$ 8.59	$ 13.08
Natural gas ($/Mcf) (1)			
North America	**$ 0.09**	$ 0.18	$ 0.03
Offshore Africa	**$ 1.57**	$ 1.74	$ 1.53
Company average	**$ 0.12**	$ 0.21	$ 0.05
Company average ($/BOE) (1)	**$ 6.05**	$ 6.22	$ 8.23

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

North America

North America crude oil and natural gas royalties for the three months ended March 31, 2013 compared with the comparable periods reflected benchmark commodity prices and the widening of the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 16% of product sales for the first quarter of 2013 compared with 19% for the first quarter of 2012 and 13% for the fourth quarter of 2012. The fluctuations in royalties from the comparable periods were the result of changes in realized crude oil and NGLs prices. 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 for the first quarter of 2013 compared with 1% for the first quarter of 2012 and 6% for the fourth quarter of 2012. The increase in natural gas royalty rates from the first quarter of 2012 was primarily the result of the increase in realized natural gas prices, partially offset by gas cost allowance adjustments. The decrease in natural gas royalty rates from the fourth quarter of 2012 was primarily the result of 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 16% for the first quarters of 2013 and 2012, and 32% for the fourth quarter of 2012. The decrease in royalty rates from the fourth quarter of 2012 was due to adjustments to royalties on liftings during the prior period.

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

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Crude oil and NGLs ($/bbl) [(1)]			
North America	**$ 14.61**	$ 12.79	$ 15.40
North Sea	**$ 74.65**	$ 54.41	$ 36.53
Offshore Africa	**$ 25.72**	$ 22.14	$ 12.17
Company average	**$ 17.56**	$ 15.32	$ 16.78
Natural gas ($/Mcf) [(1)]			
North America	**$ 1.52**	$ 1.40	$ 1.33
North Sea	**$ 3.77**	$ 3.58	$ 3.98
Offshore Africa	**$ 2.24**	$ 3.19	$ 1.76
Company average	**$ 1.53**	$ 1.43	$ 1.34
Company average ($/BOE) [(1)]	**$ 14.74**	$ 13.11	$ 13.43

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

North America

North America crude oil and NGLs production expense for the first quarter of 2013 decreased 5% to $14.61 per bbl from $15.40 per bbl for the first quarter of 2012 and increased 14% from $12.79 per bbl for the fourth quarter of 2012. The decrease in production expense for the first quarter of 2013 from the first quarter of 2012 was primarily the result of the timing of thermal steam cycles. The increase in production expense for the first quarter of 2013 from the fourth quarter of 2012 was primarily a result of lower thermal production volumes due to the cyclic nature of thermal production as well as higher servicing costs. North America crude oil and NGLs production expense is anticipated to average $12.00 to $14.00 per bbl for 2013.

North America natural gas production expense for the first quarter of 2013 increased 14% to $1.52 per Mcf from $1.33 per Mcf for the first quarter of 2012 and increased 9% from $1.40 per Mcf for the fourth quarter of 2012. Natural gas production expense increased from the first quarter of 2012 due to lower production volumes related to the reduction in natural gas activity. Natural gas production expense increased from the fourth quarter of 2012 due to the impact of normal seasonal costs associated with winter access and colder weather. North America natural gas production expense is anticipated to average $1.30 to $1.40 per Mcf for 2013.

North Sea

North Sea crude oil production expense for the first quarter of 2013 increased 104% to $74.65 per bbl from $36.53 per bbl for the first quarter of 2012 and increased 37% from $54.41 per bbl for the fourth quarter of 2012. Production expense increased on a per barrel basis from the comparable periods due to the impact of production declines on relatively fixed costs as well as higher maintenance activity and increased fuel costs. North Sea crude oil production expense 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 for the first quarter of 2013 averaged $25.72 per bbl, an increase of 111% from $12.17 per bbl for the first quarter of 2012, and an increase of 16% from $22.14 per bbl for the fourth quarter of 2012. Production expense increased from the comparable periods as a result of the timing of liftings from various fields, which have different cost structures, and the impact of production declines on relatively fixed costs. Offshore Africa crude oil production expense is anticipated to average $33.50 to $37.50 per bbl for 2013 due to timing of liftings from various fields, which have different cost structures.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Expense ($ millions)	**$ 1,023**	$ 1,097	$ 910
$/BOE (1)	**$ 19.99**	$ 20.66	$ 17.73

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

Depletion, depreciation and amortization expense increased for the first quarter of 2013 compared with the first quarter of 2012 due to higher sales volumes in North America associated with heavy oil drilling and higher overall future development costs. The decrease in depletion, depreciation and amortization expense from the fourth quarter of 2012 was primarily due to lower sales volumes in North America.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Expense ($ millions)	**$ 34**	$ 30	$ 29
$/BOE (1)	**$ 0.66**	$ 0.56	$ 0.56

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

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

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

Due to the Company's strong operating performance at Horizon and its continued focus on efficient and effective operations and emphasis on safe, steady, reliable operations, first quarter 2013 production was 108,782 bbl/d. In May 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, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

($/bbl) [1]	Three Months Ended **Mar 31 2013**	Dec 31 2012	Mar 31 2012
SCO sales price [2]	**$ 96.19**	$ 89.40	$ 99.20
Bitumen value for royalty purposes [3]	**$ 60.47**	$ 58.12	$ 64.37
Bitumen royalties [4]	**$ 3.81**	$ 3.80	$ 5.16
Transportation	**$ 1.58**	$ 2.06	$ 2.11

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period during suspension of production.
(2) Comparative figures have been adjusted to reflect realized product prices before transportation costs.
(3) Calculated as the 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 $96.19 per bbl for the first quarter of 2013, a decrease of 3% compared with $99.20 per bbl for the first quarter of 2012, and an increase of 8% compared with $89.40 per bbl for the fourth quarter of 2012, reflecting benchmark pricing and prevailing differentials.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

($ millions)	Three Months Ended **Mar 31 2013**	Dec 31 2012	Mar 31 2012
Cash production costs	**$ 377**	$ 372	$ 346
Less: costs incurred during the period of suspension of production	**–**	–	(154)
Adjusted cash production costs	**$ 377**	$ 372	$ 192
Adjusted cash production costs, excluding natural gas costs	**$ 349**	$ 342	$ 177
Adjusted natural gas costs	**28**	30	15
Adjusted cash production costs	**$ 377**	$ 372	$ 192

($/bbl) [1]	Three Months Ended **Mar 31 2013**	Dec 31 2012	Mar 31 2012
Adjusted cash production costs, excluding natural gas costs	**$ 36.95**	$ 45.31	$ 42.70
Adjusted natural gas costs	**2.98**	3.96	3.54
Adjusted cash production costs	**$ 39.93**	$ 49.27	$ 46.24
Sales (bbl/d) [2]	**105,000**	81,936	45,741

(1) Adjusted cash production costs on a per unit basis in the first quarter of 2012 were based on sales volumes excluding the period during suspension of production.
(2) Sales on a per unit basis reflect sales volumes including the period during suspension of production.

Adjusted cash production costs for the first quarter of 2013 averaged $39.93 per bbl, a decrease of 14% compared with $46.24 per bbl for the first quarter of 2012 and a decrease of 19% compared with $49.27 per bbl for the fourth quarter of 2012, primarily due to the impact of higher 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 Mar 31 2013	Dec 31 2012	Mar 31 2012
Depletion, depreciation and amortization	**$ 117**	$ 114	$ 63
Less: depreciation incurred during the period of suspension of production	**–**	–	(6)
Adjusted depletion, depreciation and amortization	**$ 117**	$ 114	$ 57
$/bbl (1)	**$ 12.35**	$ 15.12	$ 13.81

(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 Mar 31 2013	Dec 31 2012	Mar 31 2012
Expense	**$ 8**	$ 8	$ 8
$/bbl (1)	**$ 0.90**	$ 1.06	$ 1.91

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

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

MIDSTREAM

($ millions)	Three Months Ended Mar 31 2013	Dec 31 2012	Mar 31 2012
Revenue	**$ 27**	$ 26	$ 21
Production expense	**8**	8	7
Midstream cash flow	**19**	18	14
Depreciation	**2**	2	2
Equity loss from jointly controlled entity	**2**	3	–
Segment earnings before taxes	**$ 15**	$ 13	$ 12

Midstream operating results were consistent with the comparable periods.

The Company has a 50% interest in the North West Redwater Partnership (“Redwater”). 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.

ADMINISTRATION EXPENSE

($ millions)	Three Months Ended **Mar 31 2013**	Dec 31 2012	Mar 31 2012
Expense	**$ 79**	$ 64	$ 65
$/BOE (1)	**$ 1.30**	$ 1.07	$ 1.17

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

Administration expense for the first quarter of 2013 increased from the comparable periods primarily due to higher staffing related costs and general corporate costs.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended **Mar 31 2013**	Dec 31 2012	Mar 31 2012
Expense (recovery)	**$ 71**	$ (41)	$ (107)

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 $71 million share-based compensation expense for the three months ended March 31, 2013, primarily as a result of remeasurement of the fair value of outstanding stock options at the end of the period related to an increase in the Company's share price, together with the impact of normal course graded vesting of stock options granted in prior periods and the impact of vested stock options exercised or surrendered during the period. For the three months ended March 31, 2013, the Company capitalized $11 million in respect of share-based compensation expense to Oil Sands Mining and Upgrading (December 31, 2012 – $3 million recovery; March 31, 2012 – $7 million recovery).

For the three months ended March 31, 2013, the Company paid $1 million for stock options surrendered for cash settlement (December 31, 2012 – $nil; March 31, 2012 – $7 million).

INTEREST AND OTHER FINANCING COSTS

($ millions, except per BOE amounts)	Three Months Ended **Mar 31 2013**	Dec 31 2012	Mar 31 2012
Expense, gross	**$ 113**	$ 115	$ 114
Less: capitalized interest	**36**	32	18
Expense, net	**$ 77**	$ 83	$ 96
$/BOE (1)	**$ 1.27**	$ 1.37	$ 1.72
Average effective interest rate	**4.5%**	4.8%	4.8%

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

Gross interest and other financing costs for the first quarter of 2013 were consistent with the comparable periods. Capitalized interest of $36 million for the three months ended March 31, 2013 was related to the Horizon Phase 2/3 expansion and the Kirby Thermal Oil Sands Project ("Kirby Project").

The Company's average effective interest rate for the first quarter of 2013 decreased from the fourth quarter of 2012 primarily due to the repayment of $400 million of 4.50% medium-term notes and US$400 million of 5.15% unsecured notes, utilizing cash flow from operating activities generated in excess of capital expenditures and available bank credit facilities as necessary. The decrease from the first quarter of 2012 was primarily due to the factors noted above, in addition to the Company's repayment of US$350 million of 5.45% unsecured notes in the fourth quarter of 2012.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended		
($ millions)	**Mar 31 2013**	Dec 31 2012	Mar 31 2012
Crude oil and NGLs financial instruments	**$ –**	$ 19	$ 9
Foreign currency contracts	**(83)**	(27)	85
Realized (gain) loss	**$ (83)**	$ (8)	$ 94
Crude oil and NGLs financial instruments	**$ 24**	$ 29	$ 96
Foreign currency contracts	**38**	(21)	(36)
Unrealized loss	**$ 62**	$ 8	$ 60
Net (gain) loss	**$ (21)**	$ –	$ 154

Complete details related to outstanding derivative financial instruments at March 31, 2013 are disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

The Company recorded a net unrealized loss of $62 million ($51 million after-tax) on its risk management activities for the three months ended March 31, 2013 (December 31, 2012 – unrealized loss of $8 million; $4 million after-tax; March 31, 2012 – unrealized loss of $60 million; $40 million after-tax).

FOREIGN EXCHANGE

	Three Months Ended		
($ millions)	**Mar 31 2013**	Dec 31 2012	Mar 31 2012
Net realized (gain) loss	**$ (32)**	$ (196)	$ 6
Net unrealized loss (gain) (1)	**78**	254	(60)
Net loss (gain)	**$ 46**	$ 58	$ (54)

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

The net realized foreign exchange gain for the three months ended March 31, 2013 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$400 million of 5.15% unsecured notes. The net unrealized foreign exchange loss for the three months ended March 31, 2013 was primarily related to the impact of the weakening of the Canadian dollar with respect to remaining US dollar debt and the reversal of the life-to-date unrealized foreign exchange gain on the repayment of US$400 million of 5.15% unsecured notes. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended March 31, 2013 – unrealized gain of $49 million, December 31, 2012 – unrealized gain of $27 million, March 31, 2012 – unrealized loss of $42 million). The US/Canadian dollar exchange rate ended the first quarter of 2013 at US$0.9846 (December 31, 2012 – US$1.0051; March 31, 2012 – US$1.0009).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Mar 31 2013**	Dec 31 2012	Mar 31 2012
North America (1)	**$ 122**	$ 68	$ 113
North Sea	**(7)**	29	45
Offshore Africa	**35**	56	36
PRT (recovery) expense – North Sea	**(13)**	31	31
Other taxes	**4**	5	6
Current income tax expense	**141**	189	231
Deferred income tax recovery	**(4)**	(34)	(48)
Deferred PRT recovery – North Sea	**(23)**	(35)	(4)
Deferred income tax recovery	**(27)**	(69)	(52)
	$ 114	$ 120	$ 179
Effective income tax rate on adjusted net earnings from operations (2)	**28.1%**	25.5%	35.6%

(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.

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 Mar 31 2013	Dec 31 2012	Mar 31 2012
Exploration and Evaluation			
Net expenditures	**$ 77**	$ 10	$ 208
Property, Plant and Equipment			
Net property acquisitions	**11**	76	38
Well drilling, completion and equipping	**555**	566	499
Production and related facilities	**537**	495	505
Capitalized interest and other [2]	**28**	23	30
Net expenditures	**1,131**	1,160	1,072
Total Exploration and Production	**1,208**	1,170	1,280
Oil Sands Mining and Upgrading			
Horizon Phases 2/3 construction costs	**355**	423	192
Sustaining capital	**51**	94	37
Turnaround costs	**17**	5	2
Capitalized interest and other [2]	**38**	19	3
Total Oil Sands Mining and Upgrading	**461**	541	234
Midstream	**5**	4	1
Abandonments [3]	**55**	41	76
Head office	**7**	11	5
Total net capital expenditures	**$ 1,736**	$ 1,767	$ 1,596
By segment			
North America	**$ 1,093**	$ 1,086	$ 1,223
North Sea	**85**	55	54
Offshore Africa	**30**	29	3
Oil Sands Mining and Upgrading	**461**	541	234
Midstream	**5**	4	1
Abandonments [3]	**55**	41	76
Head office	**7**	11	5
Total	**$ 1,736**	$ 1,767	$ 1,596

(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) 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 first quarter of 2013 were $1,736 million compared with $1,596 million for the first quarter of 2012 and $1,767 million for the fourth quarter of 2012.

The increase in capital expenditures for the first quarter of 2013 from the first quarter of 2012 was primarily due to the ramp up of Horizon site construction activity and an increase in well drilling and completions spending, partially offset by lower exploration and evaluation expenditures. The slight decrease in capital expenditures from the fourth quarter of 2012 was primarily related to the decrease in Horizon site construction activity and net property acquisitions, partially offset by higher production and related facilities, and exploration and evaluation expenditures.

Drilling Activity (number of wells)

	Three Months Ended		
	Mar 31 2013	Dec 31 2012	Mar 31 2012
Net successful natural gas wells	**15**	3	19
Net successful crude oil wells [(1)]	**300**	294	278
Dry wells	**5**	19	6
Stratigraphic test / service wells	**305**	116	584
Total	**625**	432	887
Success rate (excluding stratigraphic test / service wells)	**98%**	94%	98%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 66% of the total capital expenditures for the three months ended March 31, 2013 compared with approximately 82% for the three months ended March 31, 2012.

During the first quarter of 2013, the Company targeted 16 net natural gas wells, including 10 wells in Northeast British Columbia, 5 wells in Northwest Alberta and 1 well in Northern Plains. The Company also targeted 304 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, 4 Pelican Lake heavy crude oil wells, and 33 bitumen (thermal oil) wells were drilled. Another 41 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall Primrose thermal production for the first quarter of 2013 averaged approximately 109,000 bbl/d compared with approximately 80,000 bbl/d for the first quarter of 2012 and approximately 121,000 bbl/d for the fourth 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 late 2013.

The next planned phase of the Company's in situ Oil Sands assets expansion is the Kirby South Phase 1 Project. As at March 31, 2013, the overall project was 94% complete, drilling was completed on the sixth of seven pads, and first steam is targeted for the third quarter of 2013.

Development of the tertiary recovery conversion projects at Pelican Lake continued and 4 horizontal wells were drilled during the quarter. Pelican Lake production averaged approximately 38,000 bbl/d for the first quarter of 2013 compared with 39,000 bbl/d for the first quarter of 2012 and 36,000 bbl/d for the fourth quarter of 2012. Pelican Lake and Woodenhouse production volumes are currently restricted due to facility constraints. These facility constraints will be alleviated as a result of the completion of the new 20,000 bbl/d battery expansion targeted to be on stream in June 2013.

For the second quarter of 2013, the Company's overall planned drilling activity in North America is expected to be 127 net crude oil wells, 27 net bitumen wells and 8 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the first quarter of 2013 was focused on field construction of the gas recovery unit, sulphur recovery unit, butane treatment unit, coker expansion, tanks farms, tailings, hydrotransport and extraction trains 3 and 4, along with engineering related to the hydrogen unit, hydrotreater unit, 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 undergoing repairs. 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 received approval for the Brownfield Allowance for the Tiffany field in January 2013 and as a result, has commenced drilling additional production wells.

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. Drilling is targeted to commence in late second quarter of 2013, but is progressing slower than anticipated due to contractor safety and performance concerns. The Company is actively engaged with the contractor to ensure the drilling program is conducted safely and efficiently.

The midwater arch at the Olowi field in Gabon has been stabilized and production was reinstated in late March 2013. The Company currently is assessing the long-term operability of the midwater arch.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Mar 31 2013**		Dec 31 2012		Mar 31 2012
Working capital deficit (1)	**$**	**1,178**	$	1,264	$	1,304
Long-term debt (2) (3)	**$**	**9,322**	$	8,736	$	8,241
Share capital	**$**	**3,742**	$	3,709	$	3,674
Retained earnings		**20,564**		20,516		19,656
Accumulated other comprehensive income		**68**		58		59
Shareholders' equity	**$**	**24,374**	$	24,283	$	23,389
Debt to book capitalization (3) (4)		**28%**		26%		26%
Debt to market capitalization (3) (5)		**21%**		22%		19%
After-tax return on average common shareholders' equity (6)		**7%**		8%		14%
After-tax return on average capital employed (3) (7)		**6%**		7%		11%

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

At March 31, 2013, 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, 2012 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.

The Company established a US commercial paper program in the first quarter of 2013. Borrowings of up to a maximum US$1,500 million are authorized. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

At March 31, 2013, the Company had $2,409 million of available credit under its bank credit facilities, net of commercial paper issuances of $254 million.

During the first quarter of 2013, the Company repaid $400 million of 4.50% medium-term notes and US$400 million of 5.15% unsecured notes. The Company retired this indebtedness utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities, as necessary, while maintaining the ongoing dividend program.

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.

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.

Long-term debt was $9,322 million at March 31, 2013, resulting in a debt to book capitalization ratio of 28% (December 31, 2012 – 26%; March 31, 2012 – 26%). 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 March 31, 2013 are discussed in note 6 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at May 2, 2013, approximately 52% of currently forecasted 2013 crude oil volumes were hedged using price collars and physical crude oil sales contracts with fixed WCS differentials. Further details related to the Company's commodity related derivative financial instruments outstanding at March 31, 2013 are discussed in note 13 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at March 31, 2013, there were 1,092,264,000 common shares outstanding and 68,646,000 stock options outstanding. As at May 1, 2013, the Company had 1,090,360,000 common shares outstanding and 68,587,000 stock options outstanding.

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 April 2013, 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 2013 and ending April 2014, up to 54,635,116 common shares. The Company's Normal Course Issuer Bid announced in 2012 expired April 2013.

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

For the three months ended March 31, 2013, the Company purchased 965,700 common shares at a weighted average price of $32.72 per common share, for a total cost of $32 million. Retained earnings were reduced by $28 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2013, the Company purchased 2,000,000 common shares at a weighted average price of $31.83 per common share for a total cost of $64 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. The following table summarizes the Company's commitments as at March 31, 2013:

($ millions)	Remaining 2013	2014	2015	2016	2017	Thereafter
Product transportation and pipeline	$ 173	$ 219	$ 205	$ 135	$ 117	$ 788
Offshore equipment operating leases and offshore drilling	$ 121	$ 145	$ 107	$ 77	$ 58	$ 68
Long-term debt [(1)]	$ 254	$ 863	$ 1,122	$ 1,506	$ 1,117	$ 4,512
Interest and other financing costs [(2)]	$ 308	$ 427	$ 383	$ 350	$ 288	$ 3,849
Office leases	$ 24	$ 34	$ 32	$ 33	$ 35	$ 262
Other	$ 140	$ 98	$ 55	$ 16	$ 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 March 31, 2013.

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.

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, refer to the unaudited interim consolidated financial statements for the three months ended March 31, 2013.

CRITICAL ACCOUNTING ESTIMATES

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 critical accounting estimates is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2012.

Consolidated Balance Sheets

As at (millions of Canadian dollars, unaudited)	Note	Mar 31 2013	Dec 31 2012
ASSETS			
Current assets			
Cash and cash equivalents		**$ 18**	$ 37
Accounts receivable		**1,443**	1,197
Inventory		**627**	554
Prepaids and other		**151**	126
		2,239	1,914
Exploration and evaluation assets	3	**2,667**	2,611
Property, plant and equipment	4	**44,550**	44,028
Other long-term assets	5	**387**	427
		$ 49,843	$ 48,980
LIABILITIES			
Current liabilities			
Accounts payable		**$ 535**	$ 465
Accrued liabilities		**2,424**	2,273
Current income tax liabilities		**180**	285
Current portion of long-term debt	6	**254**	798
Current portion of other long-term liabilities	7	**278**	155
		3,671	3,976
Long-term debt	6	**9,068**	7,938
Other long-term liabilities	7	**4,562**	4,609
Deferred income tax liabilities		**8,168**	8,174
		25,469	24,697
SHAREHOLDERS' EQUITY			
Share capital	9	**3,742**	3,709
Retained earnings		**20,564**	20,516
Accumulated other comprehensive income	10	**68**	58
		24,374	24,283
		$ 49,843	$ 48,980

Commitments and contingencies (note 14).

Approved by the Board of Directors on May 2, 2013

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Mar 31 2013	Mar 31 2012
Product sales		**$ 4,101**	$ 3,971
Less: royalties		**(346)**	(444)
Revenue		**3,755**	3,527
Expenses			
Production		**1,135**	1,038
Transportation and blending		**855**	717
Depletion, depreciation and amortization	4	**1,142**	975
Administration		**79**	65
Share-based compensation	7	**71**	(107)
Asset retirement obligation accretion	7	**42**	37
Interest and other financing costs		**77**	96
Risk management activities	13	**(21)**	154
Foreign exchange loss (gain)		**46**	(54)
Equity loss from jointly controlled entity	5	**2**	–
		3,428	2,921
Earnings before taxes		**327**	606
Current income tax expense	8	**141**	231
Deferred income tax recovery	8	**(27)**	(52)
Net earnings		**$ 213**	$ 427
Net earnings per common share			
Basic	12	**$ 0.19**	$ 0.39
Diluted	12	**$ 0.19**	$ 0.39

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2013	Mar 31 2012
Net earnings	**$ 213**	$ 427
Items that may be reclassified subsequently to net earnings		
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized income during the period, net of taxes of $2 million (2012 – $4 million)	**16**	24
Reclassification to net earnings, net of taxes of $nil (2012 – $nil)	**(1)**	1
	15	25
Foreign currency translation adjustment		
Translation of net investment	**(5)**	8
Other comprehensive income, net of taxes	**10**	33
Comprehensive income	**$ 223**	$ 460

Consolidated Statements of Changes in Equity

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Mar 31 2013	Mar 31 2012
Share capital	9		
Balance – beginning of period		**$ 3,709**	$ 3,507
Issued upon exercise of stock options		**30**	131
Previously recognized liability on stock options exercised for common shares		**7**	38
Purchase of common shares under Normal Course Issuer Bid		**(4)**	(2)
Balance – end of period		**3,742**	3,674
Retained earnings			
Balance – beginning of period		**20,516**	19,365
Net earnings		**213**	427
Purchase of common shares under Normal Course Issuer Bid	9	**(28)**	(21)
Dividends on common shares	9	**(137)**	(115)
Balance – end of period		**20,564**	19,656
Accumulated other comprehensive income	10		
Balance – beginning of period		**58**	26
Other comprehensive income, net of taxes		**10**	33
Balance – end of period		**68**	59
Shareholders' equity		**$ 24,374**	$ 23,389

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2013	Mar 31 2012
Operating activities		
Net earnings	**$ 213**	$ 427
Non-cash items		
Depletion, depreciation and amortization	**1,142**	975
Share-based compensation	**71**	(107)
Asset retirement obligation accretion	**42**	37
Unrealized risk management loss	**62**	60
Unrealized foreign exchange loss (gain)	**78**	(60)
Realized foreign exchange gain on repayment of US dollar debt securities	**(12)**	–
Equity loss from jointly controlled entity	**2**	–
Deferred income tax recovery	**(27)**	(52)
Other	**38**	23
Abandonment expenditures	**(55)**	(76)
Net change in non-cash working capital	**(389)**	230
	1,165	1,457
Financing activities		
Issue (repayment) of bank credit facilities and commercial paper, net	**1,256**	(207)
Repayment of medium-term notes	**(400)**	–
Repayment of US dollar debt securities	**(398)**	–
Issue of common shares on exercise of stock options	**30**	131
Purchase of common shares under Normal Course Issuer Bid	**(32)**	(23)
Dividends on common shares	**(115)**	(99)
Net change in non-cash working capital	**(6)**	(3)
	335	(201)
Investing activities		
Expenditures on exploration and evaluation assets and property, plant and equipment	**(1,681)**	(1,520)
Net change in non-cash working capital	**162**	243
	(1,519)	(1,277)
Decrease in cash and cash equivalents	**(19)**	(21)
Cash and cash equivalents – beginning of period	**37**	34
Cash and cash equivalents – end of period	**$ 18**	$ 13
Interest paid	**$ 142**	$ 133
Income taxes paid	**$ 213**	$ 265

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 ("IASB"), 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, 2012, except as discussed in note 2. 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, 2012.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2013, the Company adopted the following new accounting standards issued by the IASB:

a)
- IFRS 10 "Consolidated Financial Statements" replaced IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee ("SIC") 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on applying the control principle to determine whether an investor controls an investee.
- IFRS 11 "Joint Arrangements" replaced IAS 31 "Interests in Joint Ventures" and SIC 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures. In a joint operation, the parties with joint control have rights to the assets and obligations for the liabilities of the joint arrangement and are required to recognize their proportionate interest in the assets, liabilities, revenues and expenses of the joint arrangement. In a joint venture, the parties have an interest in the net assets of the arrangement and are required to apply the equity method of accounting.
- IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities.
- The Company adopted these standards retrospectively.

b) IFRS 13 "Fair Value Measurement" provides guidance on applying fair value where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value. IFRS 13 was adopted prospectively. As a result of adoption of this standard, the Company has included its own credit risk in measuring the carrying amount of a risk management liability.

c) Amendments to IAS 1 “Presentation of Financial Statements” require items of other comprehensive income that may be reclassified to net earnings to be grouped together. The amendments also require that items in other comprehensive income and net earnings be presented as either a single statement or two consecutive statements. Adoption of this amended standard impacted presentation only.

d) IFRS Interpretation Committee (“IFRIC”) 20 “Stripping Costs in the Production Phase of a Surface Mine” requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved.

Adoption of these standards did not have a material impact on the Company’s consolidated financial statements.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	**North Sea**	**Offshore Africa**		
Cost					
At December 31, 2012	$ 2,564	$ –	$ 47	$ –	$ 2,611
Additions	**76**	**–**	**1**	**–**	**77**
Transfers to property, plant and equipment	**(22)**	**–**	**–**	**–**	**(22)**
Foreign exchange adjustments	**–**	**–**	**1**	**–**	**1**
At March 31, 2013	**$ 2,618**	**$ –**	**$ 49**	**$ –**	**$ 2,667**

4. 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, 2012	$ 50,324	$ 4,574	$ 3,045	$ 16,963	$ 312	$ 270	$ 75,488
Additions	**1,013**	**85**	**29**	**461**	**5**	**7**	**1,600**
Transfers from E&E assets	**22**	**–**	**–**	**–**	**–**	**–**	**22**
Disposals/derecognitions	**(52)**	**–**	**–**	**(116)**	**–**	**–**	**(168)**
Foreign exchange adjustments and other	**–**	**96**	**63**	**–**	**–**	**–**	**159**
At March 31, 2013	**$ 51,307**	**$ 4,755**	**$ 3,137**	**$ 17,308**	**$ 317**	**$ 277**	**$ 77,101**
Accumulated depletion and depreciation							
At December 31, 2012	$ 24,991	$ 2,709	$ 2,273	$ 1,202	$ 103	$ 182	$ 31,460
Expense	**867**	**112**	**40**	**117**	**2**	**4**	**1,142**
Disposals/derecognitions	**(52)**	**–**	**–**	**(116)**	**–**	**–**	**(168)**
Foreign exchange adjustments and other	**2**	**67**	**47**	**1**	**–**	**–**	**117**
At March 31, 2013	**$ 25,808**	**$ 2,888**	**$ 2,360**	**$ 1,204**	**$ 105**	**$ 186**	**$ 32,551**
Net book value							
– at March 31, 2013	**$ 25,499**	**$ 1,867**	**$ 777**	**$ 16,104**	**$ 212**	**$ 91**	**$ 44,550**
– at December 31, 2012	$ 25,333	$ 1,865	$ 772	$ 15,761	$ 209	$ 88	$ 44,028

Horizon project costs not subject to depletion	
At March 31, 2013	**$ 2,444**
At December 31, 2012	$ 2,066

In addition, the Company has capitalized costs to date of $1,180 million (December 31, 2012 – $1,021 million) related to the development of the Kirby Thermal Oil Sands Project which are not subject to depletion.

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 $11 million during the period ended March 31, 2013 (year ended December 31, 2012 – $144 million), net of associated asset retirement obligations of $10 million (year ended December 31, 2012 – $12 million). Interests in jointly controlled assets were acquired with full tax basis. No working capital or debt obligations were assumed.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once construction is substantially complete. For the period ended March 31, 2013, pre-tax interest of $36 million (March 31, 2012 – $18 million) was capitalized to property, plant and equipment using a capitalization rate of 4.5% (March 31, 2012 – 4.8%).

5. OTHER LONG-TERM ASSETS

	Mar 31 2013	Dec 31 2012
Investment in North West Redwater Partnership	**$ 308**	$ 310
Other	**79**	117
	$ 387	$ 427

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.

6. LONG-TERM DEBT

	Mar 31 2013	Dec 31 2012
Canadian dollar denominated debt		
Bank credit facilities	**$ 1,974**	$ 971
Medium-term notes	**900**	1,300
	2,874	2,271
US dollar denominated debt		
Commercial paper (March 31, 2013 – US$250 million; December 31, 2012 – US$nil)	**254**	–
US dollar debt securities (March 31, 2013 – US$6,150 million; December 31, 2012 – US$6,550 million)	**6,246**	6,517
Less: original issue discount on US dollar debt securities (1)	**(20)**	(20)
	6,480	6,497
Fair value impact of interest rate swaps on US dollar debt securities (2)	**16**	19
	6,496	6,516
Long-term debt before transaction costs	**9,370**	8,787
Less: transaction costs (1) (3)	**(48)**	(51)
	9,322	8,736
Less: current portion of commercial paper	**254**	–
current portion of other long-term debt	**–**	798
	$ 9,068	$ 7,938

(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 $16 million (December 31, 2012 – $19 million) to reflect the fair value impact of hedge accounting.

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

Bank Credit Facilities and Commercial Paper

As at March 31, 2013, the Company had in place unsecured bank credit facilities of $4,723 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.

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 established a US commercial paper program in the first quarter of 2013. Borrowings of up to a maximum US$1,500 million are authorized. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at March 31, 2013, was 2.2% (March 31, 2012 – 2.2%), and on long-term debt outstanding for the period ended March 31, 2013 was 4.5% (March 31, 2012 – 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $532 million, including an $87 million financial guarantee related to Horizon and $345 million of letters of credit related to North Sea operations, were outstanding at March 31, 2013.

Medium-Term Notes

During the first quarter of 2013, the Company repaid $400 million of 4.50% medium-term notes.

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 first quarter of 2013, the Company repaid US$400 million of 5.15% 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.

7. OTHER LONG-TERM LIABILITIES

	Mar 31 2013	Dec 31 2012
Asset retirement obligations	**$ 4,275**	$ 4,266
Share-based compensation	**228**	154
Risk management (note 13)	**255**	257
Other	**82**	87
	4,840	4,764
Less: current portion	**278**	155
	$ 4,562	$ 4,609

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.3% (December 31, 2012 – 4.3%). A reconciliation of the discounted asset retirement obligations is as follows:

	Mar 31 2013	Dec 31 2012
Balance – beginning of period	**$ 4,266**	$ 3,577
Liabilities incurred	**14**	51
Liabilities acquired	**10**	12
Liabilities settled	**(55)**	(204)
Asset retirement obligation accretion	**42**	151
Revision of estimates	**(29)**	384
Change in discount rate	**–**	315
Foreign exchange	**27**	(20)
Balance – end of period	**$ 4,275**	$ 4,266

Share-Based Compensation

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

	Mar 31 2013	Dec 31 2012
Balance – beginning of period	**$ 154**	$ 432
Share-based compensation expense (recovery)	**71**	(214)
Cash payment for stock options surrendered	**(1)**	(7)
Transferred to common shares	**(7)**	(45)
Capitalized to (recovered from) Oil Sands Mining and Upgrading	**11**	(12)
Balance – end of period	**228**	154
Less: current portion	**188**	129
	$ 40	$ 25

8. INCOME TAXES

The provision for income tax is as follows:

	Three Months Ended	
	Mar 31 2013	Mar 31 2012
Current corporate income tax – North America	**$ 122**	$ 113
Current corporate income tax – North Sea	**(7)**	45
Current corporate income tax – Offshore Africa	**35**	36
Current PRT [(1)] expense – North Sea	**(13)**	31
Other taxes	**4**	6
Current income tax expense	**141**	231
Deferred corporate income tax recovery	**(4)**	(48)
Deferred PRT [(1)] recovery – North Sea	**(23)**	(4)
Deferred income tax recovery	**(27)**	(52)
Income tax expense	**$ 114**	$ 179

(1) Petroleum Revenue Tax.

9. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Three Months Ended Mar 31, 2013	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,092,072**	**$ 3,709**
Issued upon exercise of stock options	**1,158**	**30**
Previously recognized liability on stock options exercised for common shares	**–**	**7**
Purchase of common shares under Normal Course Issuer Bid	**(966)**	**(4)**
Balance – end of period	**1,092,264**	**$ 3,742**

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

In April 2013, 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 2013 and ending April 2014, up to 54,635,116 common shares. The Company's Normal Course Issuer Bid announced in 2012 expired April 2013.

For the three months ended March 31, 2013, the Company purchased 965,700 common shares at a weighted average price of $32.72 per common share, for a total cost of $32 million. Retained earnings were reduced by $28 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2013, the Company purchased 2,000,000 common shares at a weighted average price of $31.83 per common share for a total cost of $64 million.

Stock Options

The following table summarizes information relating to stock options outstanding at March 31, 2013:

	Three Months Ended Mar 31, 2013		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**73,747**	**$**	**34.13**
Granted	**4,759**	**$**	**29.64**
Surrendered for cash settlement	**(73)**	**$**	**23.88**
Exercised for common shares	**(1,158)**	**$**	**25.51**
Forfeited	**(8,629)**	**$**	**35.15**
Outstanding – end of period	**68,646**	**$**	**33.84**
Exercisable – end of period	**21,345**	**$**	**33.80**

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

10. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		Mar 31 2013		Mar 31 2012
Derivative financial instruments designated as cash flow hedges	**$**	**101**	$	87
Foreign currency translation adjustment		**(33)**		(28)
	$	**68**	$	59

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 March 31, 2013, the ratio was within the target range at 28%.

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

		Mar 31 2013		Dec 31 2012
Long-term debt [1]	**$**	**9,322**	$	8,736
Total shareholders' equity	**$**	**24,374**	$	24,283
Debt to book capitalization		**28%**		26%

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

12. NET EARNINGS PER COMMON SHARE

	Three Months Ended			
		Mar 31 2013		Mar 31 2012
Weighted average common shares outstanding – basic (thousands of shares)		**1,092,431**		1,100,154
Effect of dilutive stock options (thousands of shares)		**2,057**		4,454
Weighted average common shares outstanding – diluted (thousands of shares)		**1,094,488**		1,104,608
Net earnings	**$**	**213**	$	427
Net earnings per common share – basic	**$**	**0.19**	$	0.39
– diluted	**$**	**0.19**	$	0.39

13. FINANCIAL INSTRUMENTS

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

	Mar 31, 2013				
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	**$ 1,443**	**$ –**	**$ –**	**$ –**	**$ 1,443**
Accounts payable	**–**	**–**	**–**	**(535)**	**(535)**
Accrued liabilities	**–**	**–**	**–**	**(2,424)**	**(2,424)**
Other long-term liabilities	**–**	**(62)**	**(193)**	**(73)**	**(328)**
Long-term debt [1]	**–**	**–**	**–**	**(9,322)**	**(9,322)**
	$ 1,443	**$ (62)**	**$ (193)**	**$ (12,354)**	**$ (11,166)**

	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)

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

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

	Mar 31, 2013		
	Carrying amount	**Fair value**	
Asset (liability) (1)		**Level 1**	**Level 2**
Other long-term liabilities	**$ (255)**	**$ –**	**$ (255)**
Fixed rate long-term debt (2) (3) (4)	**(7,094)**	**(8,289)**	**–**
	$ (7,349)	**$ (8,289)**	**$ (255)**

	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)

(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 $16 million (December 31, 2012 – $19 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 fixed rate long-term debt.

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

Asset (liability)	**Mar 31, 2013**	Dec 31, 2012
Derivatives held for trading		
Crude oil price collars	**$ (40)**	$ (16)
Foreign currency forward contracts	**(22)**	20
Cash flow hedges		
Foreign currency forward contracts	**(2)**	–
Cross currency swaps	**(191)**	(261)
	$ (255)	$ (257)
Included within:		
Current portion of other long-term liabilities	**$ (68)**	$ (4)
Other long-term liabilities	**(187)**	(253)
	$ (255)	$ (257)

For the period ended March 31, 2013 the Company recognized a gain of $4 million (December 31, 2012 – gain of $1 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)	**Three Months Ended Mar 31, 2013**	Year Ended Dec 31, 2012
Balance – beginning of period	**$ (257)**	$ (274)
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	**(62)**	42
Foreign exchange	**47**	(53)
Other comprehensive income	**17**	28
Balance – end of period	**(255)**	(257)
Less: current portion	**(68)**	(4)
	$ (187)	$ (253)

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

	Three Months Ended	
	Mar 31 2013	Mar 31 2012
Net realized risk management (gain) loss	**$ (83)**	$ 94
Net unrealized risk management loss	**62**	60
	$ (21)	$ 154

Financial Risk Factors

a) Market risk

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

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At March 31, 2013, 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								
Price collars	Apr 2013	–	Jun 2013	50,000 bbl/d	US$80.00	–	US$145.07	Brent
	Apr 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$135.59	Brent
	Jul 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$132.18	Brent
	Apr 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$97.73	WTI
	Apr 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$110.34	WTI
	Apr 2013	–	Dec 2013	50,000 bbl/d	US$80.00	–	US$111.05	WTI

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At March 31, 2013, 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, commercial paper 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 debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At March 31, 2013, the Company had the following cross currency swap contracts outstanding:

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

All cross currency swap derivative financial instruments designated as hedges at March 31, 2013, were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at March 31, 2013, the Company had US$2,617 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$250 million classified as cash flow hedges.

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At March 31, 2013, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At March 31, 2013, the Company had no net risk management assets with specific counterparties related to derivative financial instruments (December 31, 2012 – $18 million).

c) Liquidity risk

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

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper 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	$ 535	$ –	$ –	$ –
Accrued liabilities	$ 2,424	$ –	$ –	$ –
Risk management	$ 68	$ 47	$ 98	$ 42
Other long-term liabilities	$ 22	$ 21	$ 30	$ –
Long-term debt (1)	$ 254	$ 863	$ 4,151	$ 4,106

(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:

	Remaining 2013	2014	2015	2016	2017	Thereafter
Product transportation and pipeline	$ 173	$ 219	$ 205	$ 135	$ 117	$ 788
Offshore equipment operating leases and offshore drilling	$ 121	$ 145	$ 107	$ 77	$ 58	$ 68
Office leases	$ 24	$ 34	$ 32	$ 33	$ 35	$ 262
Other	$ 140	$ 98	$ 55	$ 16	$ 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

(millions of Canadian dollars, unaudited)	Exploration and Production							
	North America Three months ended Mar 31		North Sea Three months ended Mar 31		Offshore Africa Three months ended Mar 31		Total Exploration and Production Three months ended Mar 31	
	2013	2012	**2013**	2012	**2013**	2012	**2013**	2012
Segmented product sales	**2,808**	3,058	**177**	279	**208**	217	**3,193**	3,554
Less: royalties	**(276)**	(388)	**(1)**	(1)	**(33)**	(34)	**(310)**	(423)
Segmented revenue	**2,532**	2,670	**176**	278	**175**	183	**2,883**	3,131
Segmented expenses								
Production	**605**	582	**102**	85	**47**	22	**754**	689
Transportation and blending	**855**	715	**2**	3	**–**	–	**857**	718
Depletion, depreciation and amortization	**871**	798	**112**	84	**40**	28	**1,023**	910
Asset retirement obligation accretion	**23**	21	**9**	7	**2**	1	**34**	29
Realized risk management activities	**(83)**	94	**–**	–	**–**	–	**(83)**	94
Equity loss from jointly controlled entity	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**2,271**	2,210	**225**	179	**89**	51	**2,585**	2,440
Segmented earnings (loss) before the following	**261**	460	**(49)**	99	**86**	132	**298**	691
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								
Net earnings								

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading Three months ended Mar 31		Midstream Three months ended Mar 31		Inter-segment elimination and other Three months ended Mar 31		Total Three months ended Mar 31	
	2013	2012	**2013**	2012	**2013**	2012	**2013**	2012
Segmented product sales	**909**	414	**27**	21	**(28)**	(18)	**4,101**	3,971
Less: royalties	**(36)**	(21)	**–**	–	**–**	–	**(346)**	(444)
Segmented revenue	**873**	393	**27**	21	**(28)**	(18)	**3,755**	3,527
Segmented expenses								
Production	**377**	346	**8**	7	**(4)**	(4)	**1,135**	1,038
Transportation and blending	**15**	12	**–**	–	**(17)**	(13)	**855**	717
Depletion, depreciation and amortization	**117**	63	**2**	2	**–**	–	**1,142**	975
Asset retirement obligation accretion	**8**	8	**–**	–	**–**	–	**42**	37
Realized risk management activities	**–**	–	**–**	–	**–**	–	**(83)**	94
Equity loss from jointly controlled entity	**–**	–	**2**	–	**–**	–	**2**	–
Total segmented expenses	**517**	429	**12**	9	**(21)**	(17)	**3,093**	2,861
Segmented earnings (loss) before the following	**356**	(36)	**15**	12	**(7)**	(1)	**662**	666
Non-segmented expenses								
Administration							**79**	65
Share-based compensation							**71**	(107)
Interest and other financing costs							**77**	96
Unrealized risk management activities							**62**	60
Foreign exchange loss (gain)							**46**	(54)
Total non-segmented expenses							**335**	60
Earnings before taxes							**327**	606
Current income tax expense							**141**	231
Deferred income tax recovery							**(27)**	(52)
Net earnings							**213**	427

Capital Expenditures (1)

	Period Ended					
	Mar 31, 2013			Mar 31, 2012		
	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	**$ 76**	**$ (22)**	**$ 54**	$ 208	$ (39)	$ 169
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa	**1**	**–**	**1**	–	–	–
	$ 77	**$ (22)**	**$ 55**	$ 208	$ (39)	$ 169
Property, plant and equipment						
Exploration and Production						
North America	**$ 1,017**	**$ (34)**	**$ 983**	$ 1,015	$ 52	$ 1,067
North Sea	**85**	**–**	**85**	54	2	56
Offshore Africa	**29**	**–**	**29**	3	–	3
	1,131	**(34)**	**1,097**	1,072	54	1,126
Oil Sands Mining and Upgrading (3)	**461**	**(116)**	**345**	234	1	235
Midstream	**5**	**–**	**5**	1	–	1
Head office	**7**	**–**	**7**	5	–	5
	$ 1,604	**$ (150)**	**$ 1,454**	$ 1,312	$ 55	$ 1,367

(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.

Segmented Assets

	Total Assets	
	Mar 31 2013	Dec 31 2012
Exploration and Production		
North America	**$ 29,282**	$ 29,012
North Sea	**2,046**	1,993
Offshore Africa	**981**	924
Other	**40**	36
Oil Sands Mining and Upgrading	**16,726**	16,291
Midstream	**677**	636
Head office	**91**	88
	$ 49,843	$ 48,980

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

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

Interest coverage ratios for the twelve month period ended March 31, 2013:

Interest coverage (times)	
Net earnings (1)	5.9x
Cash flow from operations (2)	15.8x

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

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

Corporate Information

Board of Directors

Catherine M. Best, FCA, ICD.D
N. Murray Edwards
Timothy W. Faithfull
Honourable Gary A. Filmon, P.C., O.C., O.M.
Christopher L. Fong
Ambassador Gordon D. Giffin
Wilfred A. Gobert
Steve W. Laut
Keith A.J. MacPhail
Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C.
James S. Palmer, C.M., A.O.E., Q.C.
Dr. Eldon R. Smith, O.C., M.D.
David A. Tuer

Officers

N. Murray Edwards
Chairman of the Board

John G. Langille
Vice-Chairman

Steve W. Laut
President

Tim S. McKay
Executive Vice-President & Chief Operating Officer

Corey B. Bieber
Chief Financial Officer & Senior Vice-President Finance

Douglas A. Proll
Executive Vice-President

Réal M. Cusson
Senior Vice-President, Marketing

Réal J.H. Doucet
Senior Vice-President, Horizon Projects

Peter J. Janson
Senior Vice-President, Horizon Operations

Terry J. Jocksch
Senior Vice-President, Thermal & International

Allen M. Knight
Senior Vice-President, International & Corporate Development

Bill R. Peterson
Senior Vice-President, Production, Drilling & Completions

Scott G. Stauth
Senior Vice-President, North America Operations

Lyle G. Stevens
Senior Vice-President, Exploitation

Jeff W. Wilson
Senior Vice-President, Exploration

Mary-Jo E. Case
Vice-President, Land

Randall S. Davis
Vice-President, Finance & Accounting

Bruce E. McGrath
Corporate Secretary

International Operations
CNR International (U.K.) Limited
Aberdeen, Scotland

James A. Edens
Vice-President & Managing Director International

W. David R. Bell
Vice-President, Exploration, International

Barry Duncan
Vice-President, Finance, International

David M. Haywood
Vice-President, Operations, International

Andrew M. McBoyle
Vice-President, Exploitation, International

David B. Whitehouse
Vice-President, Production Operations, International

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Investor Relations

Telephone: (403) 514-7777
Email: ir@cnrl.com

This page left intentionally blank

C A N A D I A N N A T U R A L R E S O U R C E S L I M I T E D

2500, 855 - 2 Street S.W., Calgary, Alberta T2P 4J8

Telephone: (403) 517-6700   Facsimile: (403) 517-7350

Website: www.cnrl.com

Printed in Canada