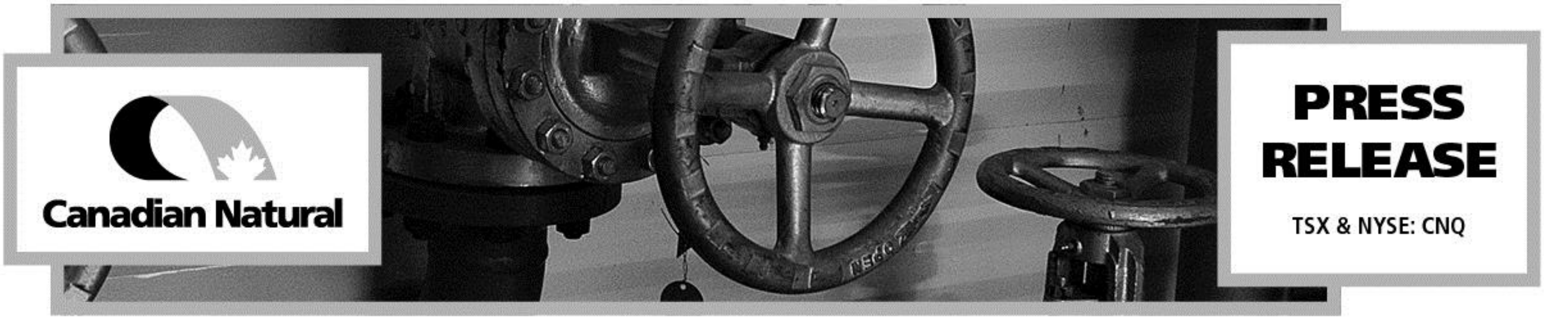


## CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES
## 2014 FIRST QUARTER RESULTS
## CALGARY, ALBERTA – MAY 8, 2014 – FOR IMMEDIATE RELEASE

Commenting on first quarter results, Steve Laut, President of Canadian Natural stated, “Canadian Natural had a solid start to the year, with consistent organic growth in North America production as expected. North America E&P crude oil and NGLs production grew by 5% over the previous quarter. Subsequent to the quarter the acquisition of certain assets closed, the integration of people is now complete and the integration of those assets is progressing. We have expanded our strong portfolio, which we will continue to develop in a prudent and disciplined manner, enabling us to maximize value for our shareholders. As a result of the recent acquisitions and our ongoing development opportunities, our 2014 development capital budget has been increased by $425 million and our 2014 annual production guidance has increased, with the midpoint of crude oil and NGLs production increasing by 3% or 15,000 barrels per day, and the midpoint of natural gas production increasing by 30% or 360 million cubic feet per day.

Canadian Natural continues to execute on its defined growth plan and achieved record quarterly production in primary heavy crude oil, Pelican Lake heavy crude oil and North America light crude oil and NGLs. Additionally, we had continued strong production at Horizon, with quarterly production averaging 113,000 barrels per day, and April 2014 production of approximately 119,000 barrels per day. Our Kirby South SAGD project is progressing well and we are targeting a strong ramp up in production to the 40,000 barrel per day facility capacity by the end of 2014.

We will continue to focus on execution and capital discipline to deliver on our defined growth plan. This prudent development of our diverse asset base enables us to generate increasing free cash flow to allocate to resource development, sustainable dividends, share purchases, opportunistic acquisitions, and debt repayment.”

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “The solid production growth this quarter combined with strong crude oil and natural gas pricing, led to an increase in cash flow by 20% over the fourth quarter of 2013.

We have demonstrated the value of our large and diverse asset base as we remain on track to deliver a solid year of cash flow generation. This increase in cash flow enables us to maximize returns to our shareholders in the form of sustainable dividends and share purchases. During the first quarter of 2014 we increased our quarterly dividend to $0.225 per common share from $0.20 per common share. This is our fourteenth consecutive year of quarterly dividend increases and represents a year over year increase of 80% in the quarterly dividend. Subsequent to the quarter, we renewed our Normal Course Issuer Bid. In 2014, year to date, we have purchased 2,105,000 common shares at an average price of $37.86 per common share.

Our disciplined strategy and financial strength will enable us to continue to execute on the significant growth opportunities which we have in the near, mid and long-term.”

## QUARTERLY HIGHLIGHTS

| ($ Millions, except per common share amounts) | Three Months Ended Mar 31 2014 | Dec 31 2013 | Mar 31 2013 |
|---|---|---|---|
| Net earnings | **$ 622** | $ 413 | $ 213 |
| Per common share – basic | **$ 0.57** | $ 0.38 | $ 0.19 |
| – diluted | **$ 0.57** | $ 0.38 | $ 0.19 |
| Adjusted net earnings from operations (1) | **$ 921** | $ 563 | $ 401 |
| Per common share – basic | **$ 0.85** | $ 0.52 | $ 0.37 |
| – diluted | **$ 0.85** | $ 0.52 | $ 0.37 |
| Cash flow from operations (2) | **$ 2,146** | $ 1,782 | $ 1,571 |
| Per common share – basic | **$ 1.97** | $ 1.64 | $ 1.44 |
| – diluted | **$ 1.97** | $ 1.64 | $ 1.44 |
| Capital expenditures, net of dispositions | **$ 1,893** | $ 2,091 | $ 1,736 |
| Daily production, before royalties | | | |
| Natural gas (MMcf/d) | **1,175** | 1,195 | 1,150 |
| Crude oil and NGLs (bbl/d) | **488,788** | 478,038 | 489,157 |
| Equivalent production (BOE/d) (3) | **684,647** | 677,242 | 680,844 |

*(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 $2.15 billion in Q1/14 compared to approximately $1.57 billion in Q1/13 and $1.78 billion in Q4/13. The increase in cash flow from Q4/13 reflects higher North America crude oil and NGLs and natural gas netbacks, higher North America crude oil sales volumes and the impact of the weaker Canadian dollar, offset by lower crude oil sales volumes in the Offshore Africa segment. Due to the nature of Floating Production, Storage and Offloading ("FPSO") vessel operations, no crude oil liftings or sales occurred in Offshore Africa operations during Q1/14. The resulting cash flow from Q1/14 production, to be realized in Q2/14 once liftings occur, is targeted to be approximately $50 million.
- Adjusted net earnings from operations for Q1/14 were $921 million, compared to adjusted net earnings of $401 million in Q1/13 and $563 million Q4/13. Changes in adjusted net earnings reflect the changes in cash flow from operations as well as lower depletion, depreciation and amortization expense from both Q1/13 and Q4/13.
- Total crude oil and NGLs production for Q1/14 averaged 488,788 barrels per day ("bbl/d"). The strong production performance was largely driven by:
    - record production levels in primary heavy crude oil,
    - record Pelican Lake heavy crude oil production,
    - record North America NGLs and light crude oil production,
    - continued safe, steady and reliable production at Horizon Oil Sands ("Horizon") operations.
- In Q1/14, primary heavy crude oil operations achieved record quarterly production of approximately 142,000 bbl/d. Primary heavy crude oil production increased 7% and 6% from Q1/13 and Q4/13 levels, respectively, due to strong results from the Company's effective and efficient drilling program.

- In Q1/14, Pelican Lake operations achieved record quarterly heavy crude oil production volumes of approximately 48,000 bbl/d, a 26% increase from Q1/13 volumes and a 4% increase from Q4/13 volumes. This is the fifth consecutive quarter of production increases, which reflects Canadian Natural's continued success in developing, implementing and optimizing polymer flooding technology.
- Kirby South, a 100% owned and operated SAGD project, was completed during Q3/13 ahead of schedule and on budget. The reservoir is responding as expected with Q1/14 production averaging 5,000 bbl/d and April 2014 production averaging approximately 14,000 bbl/d. Kirby South production is targeted to grow to facility capacity of 40,000 bbl/d by year end.
- The Kirby North Phase 1 ("Kirby North") project is continuing toward commencement of construction and regulatory approvals are progressing. Targeted project capital for Kirby North is $1.45 billion, equating to approximately $36,000 per flowing barrel at a project capacity of 40,000 bbl/d. Detailed engineering on the Central Processing Facility is essentially complete and first steam-in is targeted for Q4/16, subject to regulatory approvals.
- During Q1/14 Horizon continued to achieve strong and reliable operating performance, with SCO production averaging approximately 113,000 bbl/d, a 4% increase from Q1/13 levels and a 1% increase over Q4/13 levels. April 2014 SCO production averaged approximately 119,000 bbl/d. Horizon production is targeted to increase in 2014 by 11%, an average increase of 11,000 bbl/d from 2013 levels, as a result of the continued focus on effective and efficient operations.
- Q1/14 total natural gas production was 1,175 MMcf/d, an increase of 2% from Q1/13 levels and a decrease of 2% from Q4/13 levels. The increase in natural gas production from Q1/13 levels is due to the successful completion of the Septimus plant expansion, a concentrated liquids-rich natural gas drilling program, as well as minor property acquisitions. The minor decrease in natural gas production from Q4/13 was primarily a result of normal production declines.
- During Q1/14, the Company agreed to acquire certain assets in areas adjacent or proximal to Canadian Natural's current Canadian operations. These assets are high quality, concentrated liquids-rich natural gas weighted assets, with additional light crude oil exposure. The transactions closed in Q2/14 and include associated key strategic facilities, a royalty revenue stream and undeveloped land. The integration of people is now complete and Canadian Natural is working to maximize efficiencies of the integrated operations while high grading opportunities in the Company's large and diverse portfolio.
- As expected, heavy crude oil differentials narrowed during Q1/14, resulting in favorable price realizations for the Company. The WCS heavy oil differential ("WCS differential") as a percent of WTI averaged 24% in Q1/14 compared to 34% in Q1/13 and 33% in Q4/13.
- Under the Company's Normal Course Issuer Bid, Canadian Natural has purchased 2,105,000 common shares year to date for cancellation at an average price of $37.86 per common share, which includes 330,000 common shares purchased subsequent to March 31, 2014 at a weighted average price of $43.44 per common share.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.225 per share payable on July 1, 2014.

## OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in core regions where the Company owns 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 production facilities by processing its own or third party volumes, thereby increasing control over production costs. Furthermore, 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 | | | |
|---|---|---|---|---|
| | **2014** | | 2013 | |
| | **Gross** | **Net** | Gross | Net |
| Crude oil | **300** | **271** | 312 | 300 |
| Natural gas | **32** | **25** | 18 | 15 |
| Dry | **4** | **3** | 6 | 5 |
| Subtotal | **336** | **299** | 336 | 320 |
| Stratigraphic test / service wells | **330** | **330** | 305 | 305 |
| Total | **666** | **629** | 641 | 625 |
| Success rate (excluding stratigraphic test / service wells) | | **99%** | | 98% |

### North America Exploration and Production

*Crude oil and NGLs – excluding Thermal In Situ Oil Sands*

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Crude oil and NGLs production (bbl/d) | **266,110** | 254,162 | 236,600 |
| Net wells targeting crude oil | **263** | 299 | 271 |
| Net successful wells drilled | **260** | 289 | 267 |
| Success rate | **99%** | 97% | 99% |

- North America crude oil and NGLs production averaged 266,110 bbl/d in Q1/14, an increase of 12% from Q1/13 levels and 5% from Q4/13 levels.
- In Q1/14, primary heavy crude oil operations achieved record quarterly production of approximately 142,000 bbl/d. Primary heavy crude oil production increased 7% and 6% from Q1/13 and Q4/13 levels, respectively, due to strong results from the Company's effective and efficient drilling program. Canadian Natural continued with its large and cost efficient drilling program with 224 net primary heavy crude oil wells completed in Q1/14. Canadian Natural's primary heavy crude oil assets provide strong netbacks and a high return on capital in the Company's portfolio of diverse and balanced assets.
- In Q1/14, Pelican Lake operations achieved record heavy crude oil quarterly production volumes of approximately 48,000 bbl/d, a 26% increase from Q1/13 volumes and a 4% increase from Q4/13 volumes. This is the fifth consecutive quarter of production increases, which reflects Canadian Natural's continued success in developing, implementing and optimizing polymer flooding technology. Pelican Lake's industry leading operating costs of $9.65/bbl in Q1/14 represent a 28% decrease in operating costs from Q1/13. The increasing polymer flood production response combined with continued optimization and effective and efficient operations have driven cost improvements.

- North America light crude oil and NGLs achieved record quarterly production of approximately 75,900 bbl/d in Q1/14. Production increased 16% from Q1/13 levels and 3% from Q4/13 levels, as a result of a successful Q1/14 drilling program and increased NGLs production associated with the Septimus project expansion. The Company drilled 39 net light crude oil wells in Q1/14. Canadian Natural's light crude oil drilling program will continue to utilize and advance horizontal multi-frac well technology to access new reserves in pools across the Company's land base.

*Thermal In Situ Oil Sands*

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Bitumen production (bbl/d) | **82,077** | 78,069 | 108,889 |
| Net wells targeting bitumen | **11** | 38 | 33 |
| Net successful wells drilled | **11** | 35 | 33 |
| Success rate | **100%** | 92% | 100% |

- Q1/14 thermal in situ production volumes were 82,077 bbl/d, at the high end of the Company's previously issued guidance of 75,000 to 83,000 bbl/d.
- Kirby South, a 100% owned and operated SAGD project, was completed during Q3/13 ahead of schedule and on budget. The reservoir is responding as expected with Q1/14 production averaging 5,000 bbl/d and April 2014 production averaging approximately 14,000 bbl/d. At the end of Q1/14, 25 well pairs had been converted to full SAGD production with a further 4 well pairs converted to production subsequent to Q1/14. The remaining 20 well pairs are progressing through the steam circulation phase to initiate the SAGD process. The wells at Kirby South are performing as expected and production is targeted to grow to facility capacity of 40,000 bbl/d by year end.
- The Kirby North project is continuing toward commencement of construction and regulatory approvals are progressing. Targeted project capital for Kirby North is $1.45 billion, equating to approximately $36,000 per flowing barrel at a project capacity of 40,000 bbl/d. The Kirby North project includes 56 well pairs and expansion infrastructure for future growth. Detailed engineering on the Central Processing Facility is essentially complete and first steam-in is targeted for Q4/16, subject to regulatory approvals.
- During Q2/13, bitumen emulsion was discovered at surface at 4 separate locations in the Company's Primrose development area, 3 at Primrose East and 1 at Primrose South. The cleanup of all 4 sites is complete and the causation review of the bitumen emulsion seepage is nearing completion. Canadian Natural continues to work collaboratively with the Alberta Energy Regulator ("AER") on the causation review of the bitumen emulsion seepage. The Company's near term steaming plan at Primrose has been modified as a result of the seepages, with steaming being temporarily reduced in certain areas. Canadian Natural believes that reserves recovered from the Primrose area over its life cycle will be substantially unchanged and production guidance for 2014 also remains unchanged.
- Concurrent with the causation review, Canadian Natural has developed methods to prevent seepages for all potential failure mechanisms. This includes the remediation of legacy wellbores, modified steaming strategies, enhanced monitoring techniques and proactive response strategies.

*Natural Gas*

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Natural gas production (MMcf/d) | **1,147** | 1,165 | 1,125 |
| Net wells targeting natural gas | **25** | 11 | 16 |
| Net successful wells drilled | **25** | 11 | 15 |
| Success rate | **100%** | 100% | 94% |

- North America natural gas production averaged 1,147 MMcf/d for Q1/14, an increase of 2% from Q1/13 levels and a decrease of 2% from Q4/13 levels. The increase in natural gas production from Q1/13 was due to the successful completion of the Septimus plant expansion, a concentrated liquids-rich natural gas drilling program, as well as minor property acquisitions. The minor decrease in natural gas production from Q4/13 was primarily a result of normal production declines.
- Subsequent to Q1/14, Canadian Natural completed certain light crude oil and natural gas property acquisitions in areas adjacent or proximal to the Company's current operations. Canadian Natural has reviewed the opportunities across its portfolio and, to maximize value and reduce per unit production expenses, the Company will increase natural gas capital allocation by $210 million for 2014. The additional capital will be allocated to recently acquired assets to consolidate facilities, drill additional wells for land retention, conduct facility turnarounds and continue with the fabrication of the Ferrier central processing modules. These activities will enhance production while reducing the operating costs on the acquired assets.

**International Exploration and Production**

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Crude oil production (bbl/d) | | | |
| North Sea | **16,715** | 20,155 | 18,774 |
| Offshore Africa | **10,791** | 13,379 | 16,112 |
| Natural gas production (MMcf/d) | | | |
| North Sea | **7** | 7 | 1 |
| Offshore Africa | **21** | 23 | 24 |
| Net wells targeting crude oil | – | – | – |
| Net successful wells drilled | – | – | – |
| Success rate | – | – | – |

- International crude oil production averaged 27,506 bbl/d during Q1/14, an 18% decrease from Q4/13 levels, and in line with stated guidance of 26,000 to 29,000 bbl/d. This decrease was primarily as a result of a temporary shut-in at the Baobab field during the quarter, unplanned downtime at the Tiffany field, as well as the planned permanent cessation of production at Murchison in Q1/14.
- Due to the nature of FPSO vessel operations, no crude oil liftings or sales occurred in Offshore Africa operations during Q1/14. The resulting cash flow from Q1/14 production, to be realized in Q2/14 once liftings occur, is targeted to be approximately $50 million.
- Production at the Baobab field was temporarily shut-in during Q4/13 as a result of a mooring line failure on the FPSO vessel in December 2013. The Company successfully completed the permanent repairs on the mooring lines in March 2014.
- During Q4/13 the Company contracted a drilling rig for a 6 well (3.5 net) drilling program at the Baobab field in Côte d'Ivoire. This rig is expected to arrive no later than Q1/15 to commence an approximate 16-month light crude oil drilling program, which is targeted to add 11,000 BOE/d of net production when complete.

- Subsequent to Q1/14, Canadian Natural contracted a drilling rig to undertake the 12-month light crude oil infill drilling program at Espoir, Côte d'Ivoire. The development of Espoir is now targeted to commence in the second half of 2014 with a 10 well (5.9 net) drilling program. This program is targeted to add 5,900 BOE/d of net production when complete.
- Canadian Natural previously acquired two blocks in Côte d'Ivoire which are prospective for deepwater channel/fan structures similar to Jubilee crude oil discoveries in Offshore Africa. Subsequent to Q1/14, an exploratory well was drilled on Block CI-514, in which the Company has a 36% working interest. The well encountered a series of sands approximately 350 metres thick which contain a hydrocarbon column of approximately 40 metres of light oil with 34 degree API gravity. The well, which demonstrated the presence of a working petroleum system, was plugged and the data gathered will be evaluated to determine the extent of the accumulation and the future appraisal plan. These results enhance the prospectivity of Canadian Natural's Block CI-12, located approximately 35 km west of Canadian Natural's current production at Espoir and Baobab.
- In Block 11B/12B, in South Africa, the operator is targeting to commence drilling the first exploration well in Q3/14. Canadian Natural has a 50% interest in an exploration right located in the Outeniqua Basin, approximately 175 kilometers off the southern coast of South Africa.
- Banff/Kyle, with combined net production of approximately 3,500 bbl/d, was suspended in Q1/11 after suffering storm damage. The FPSO has been repaired, is back in the field and is currently being tied in to the subsea system, with production targeted to resume early in Q3/14.
- International capital guidance increased by $100 million for 2014, largely as a result of foreign exchange rate fluctuations, and, to a lesser extent, an increase in the targeted cost to drill in Offshore South Africa, in excess of Canadian Natural's carried costs.

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

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Synthetic crude oil production (bbl/d) | **113,095** | 112,273 | 108,782 |

- During Q1/14 Horizon continued to achieve strong and reliable operating performance, with SCO production averaging approximately 113,000 bbl/d, a 4% increase from Q1/13 levels and a 1% increase over Q4/13 levels. April 2014 SCO production was approximately 119,000 bbl/d. Horizon production is targeted to increase in 2014 by 11%, an average increase of 11,000 bbl/d from 2013 levels, as a result of the continued focus on effective and efficient operations.
- In Q1/14 Horizon generated strong operating cash flow due to high SCO sales volumes supported by higher realized SCO pricing. Horizon operating costs are targeted to decline with the phased expansion of production capacity.
- Canadian Natural continues to deliver on its strategy to transition to a longer life, low decline asset base while providing significant and growing free cash flow. Canadian Natural's staged expansion to 250,000 bbl/d of SCO production capacity continues to progress on track and within sanctioned cost estimates.
- The staged Phase 2/3 expansion at Horizon continues to progress in Q1/14:
    - Overall Horizon Phase 2/3 expansion is 37% physically complete.
    - Reliability – Tranche 2 is 97% physically complete. This phase will increase performance, overall production reliability and the Gas Recovery Unit will recover additional SCO barrels in 2014.
    - Directive 74 includes technological investment and research into tailings management. This project remains on track and is physically 26% complete.
    - Phase 2A is a coker expansion which will utilize pre-invested infrastructure and equipment to expand the Coker Plant and alleviate the current bottleneck. The expansion is 84% physically complete with current progress tracking ahead of schedule. The coker tie-in was originally scheduled to be completed in mid-2015; however, due to strong construction performance and the early completion of the coker installation, the Company has accelerated the tie-in to September 2014. An increase in Horizon SCO production capacity of approximately 12,000 bbl/d is targeted to occur subsequent to the completion of the coker tie-in.

- Phase 2B is 28% physically complete. This phase expands the capacity of major components such as gas/oil hydrotreatment, froth treatment and the hydrogen plant. This phase is targeted to add another 45,000 bbl/d of production capacity in 2016.
- Phase 3 is on track and on schedule. This phase is 26% physically complete, and includes the addition of supplementary extraction trains. This phase is targeted to increase production capacity by 80,000 bbl/d in 2017 and will result in additional reliability, redundancy and significant operating cost savings.
- The projects currently under construction continue to progress on track and within sanctioned cost estimates.

▪ On the Phase 2/3 expansion Canadian Natural has committed to approximately 63% of the Engineering, Procurement and Construction contracts. Over 57% of the construction contracts have been awarded to date, with 85% being lump sum, ensuring greater cost certainty.

## MARKETING

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Crude oil and NGLs pricing | | | |
| WTI benchmark price (US$/bbl) (1) | **$ 98.61** | $ 97.50 | $ 94.34 |
| WCS blend differential from WTI (%) (2) | **24%** | 33% | 34% |
| SCO price (US$/bbl) | **$ 96.45** | $ 88.37 | $ 95.24 |
| Condensate benchmark pricing (US$/bbl) | **$ 102.53** | $ 94.30 | $ 107.18 |
| Average realized pricing before risk management (C$/bbl) (3) | **$ 79.68** | $ 69.38 | $ 60.87 |
| Natural gas pricing | | | |
| AECO benchmark price (C$/GJ) | **$ 4.52** | $ 2.99 | $ 2.92 |
| Average realized pricing before risk management (C$/Mcf) | **$ 5.69** | $ 3.62 | $ 3.51 |

*(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.*

| **Benchmark Pricing** | **WTI Pricing (US$/bbl)** | **WCS Blend Differential from WTI (%)** | **SCO Differential from WTI (US$/bbl)** | **Dated Brent Differential from WTI (US$/bbl)** | **Condensate Differential from WTI (US$/bbl)** |
|---|---|---|---|---|---|
| 2014 | | | | | |
| January | $ 94.86 | 31% | $ (7.12) | $ 13.40 | $ 3.35 |
| February | $ 100.68 | 19% | $ 1.97 | $ 8.19 | $ 5.15 |
| March | $ 100.51 | 21% | $ (0.95) | $ 7.04 | $ 3.37 |
| April | $ 102.03 | 22% | $ (2.56) | $ 5.59 | $ 1.91 |
| May* | $ 99.50 | 19% | $ 4.09 | $ 8.78 | $ 3.36 |
| June* | $ 98.79 | 17% | $ 3.00 | $ 9.18 | $ 2.04 |

*Based on current indicative pricing as at May 2, 2014.*

▪ The Company average realized pricing increased in Q1/14 over Q1/13 and Q4/13 pricing due to strong benchmark pricing, narrow WCS differentials and the weakening of the Canadian dollar relative to the US dollar.

▪ Overall Q1/14 was a strong quarter for commodity pricing:

- the WCS differential narrowed to 24% in Q1/14 from 33% in Q4/13,
- the SCO price increased by 9% in Q1/14 over Q4/13 pricing to $96.45, and
- AECO natural gas prices for Q1/14 increased 51% to $4.52 over Q4/13 prices.

- The WCS differential averaged 24% during Q1/14 compared with 34% in Q1/13 and 33% in Q4/13. During Q1/14 the WCS differential narrowed due to the reinstatement of third party refinery operations after planned and unplanned maintenance, increased demand as a result of third party refinery expansion and higher refinery utilization. The Company anticipates less volatility in the WCS differential in the latter half of 2014 as additional heavy crude oil conversion and pipeline capacity come on stream.
- Subsequent to Q1/14, the WCS differential averaged 22% in April 2014, and the indicative WCS differential for May 2014 is approximately 19% and June 2014 is approximately 17%. The WCS differential is directionally tightening due to increased demand for heavier crudes, as a result of third party refinery expansion and higher refinery utilization.
- Canadian Natural contributed 172,000 bbl/d of its heavy crude oil stream to the WCS blend in Q1/14. The Company remains the largest contributor to the WCS blend, accounting for over 55% of the total blend this quarter.
- SCO pricing during Q1/14 was comparable to Q1/13 and increased 9% from Q4/13, reflecting increased demand, benchmark pricing, prevailing differentials and the alleviation of logistical constraints between Cushing, Oklahoma and the U.S. Gulf Coast.
- During Q1/14, AECO natural gas prices increased 55% over Q1/13 levels and 51% from Q4/13 levels. Natural gas prices increased due to increased winter weather related natural gas demand. The colder than normal winter resulted in natural gas storage inventories falling below five-year lows in the US and Canada.

## NORTH WEST REDWATER UPGRADING AND REFINING

The North West Redwater refinery, upon completion, will strengthen 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 pricing volatility in all Western Canadian heavy crude oil. The Company has a 50% interest in the North West Redwater Partnership. Work is progressing and site preparation and deep underground construction is underway.

## 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, US commercial paper program, diverse asset base and related capital expenditure programs and commodity hedging policy all support a flexible financial position and provide the appropriate 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 684,647 BOE/d for Q1/14 with approximately 98% of production located in G8 countries.
- During Q1/14 Canadian Natural entered into an agreement to acquire certain Canadian crude oil and natural gas properties. The acquired asset package includes a royalty revenue stream which is targeted to earn approximately $75 million in pre-tax cash flow during 2014. Canadian Natural is reviewing the options to combine the acquired royalty revenue stream with its own royalty revenue portfolio for either the creation of a new vehicle to provide steady cash flow to current shareholders or monetization through a sale package later in 2014. The targeted pre-tax cash flow from the combined royalty revenue streams is expected to be between $140 million and $150 million in 2014.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 28% and debt to EBITDA of 1.1x at March 31, 2014. On April 1, 2014, following the acquisition of certain properties for cash consideration of approximately $3.1 billion, the Company's debt to book capitalization was 34%.
- Canadian Natural maintains significant financial stability and liquidity represented by bank credit facilities. As at March 31, 2014, the Company had in place bank credit facilities of $5,803 million, of which $4,561 million, net of commercial paper issuances of $553 million, was available. Credit facilities at March 31, 2014 included a $1,000 million non-revolving term credit facility arranged in connection with the acquisition of certain producing Canadian crude oil and natural gas properties announced in Q1/14.
- During Q1/14, the Company issued US$500 million of three-month London Interbank Offered Rate ("LIBOR") plus 0.375% notes due March 2016, and concurrently, entered into cross currency swaps to fix the foreign currency exchange rate risk at three-month Canadian Dealer Offered Rate ("CDOR") plus 0.309% and $555 million. In addition, the Company issued US$500 million of 3.80% notes due April 2024. Proceeds from the securities were used to repay bank indebtedness. At March 31, 2014, the Company had maturities of long-term debt aggregating $945 million over the next 12 months (US$500 million due November 2014 and US$350 million due December 2014).

- 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. Details of the Company’s commodity hedging program can be found on the Company’s website at www.cnrl.com.
- Subsequent to Q1/14, 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 2014 and ending April 2015, purchase for cancellation on Toronto Stock Exchange and the New York Stock Exchange up to 54,596,899 common shares.
- Under the Company’s Normal Course Issuer Bid, Canadian Natural has purchased 2,105,000 common shares year to date for cancellation at an average price of $37.86 per common share, which includes 330,000 common shares purchased subsequent to March 31, 2014 at a weighted average price of $43.44 per common share.
- Canadian Natural’s Board of Directors has declared a quarterly cash dividend on common shares of C$0.225 per share payable on July 1, 2014. This represents fourteen consecutive years of dividend increases since the Company first paid a dividend in 2001, with a compound annual growth rate of 34% from 2009 when Horizon first commenced production.

**OUTLOOK**

The Company forecasts 2014 production levels before royalties to average between 537,000 and 574,000 bbl/d of crude oil and NGLs and between 1,530 and 1,570 MMcf/d of natural gas. The 2014 production guidance has been revised to reflect certain crude oil and natural gas property acquisitions which have closed to date. Q2/14 production guidance before royalties is forecast to average between 519,000 and 546,000 bbl/d of crude oil and NGLs and between 1,620 and 1,660 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company’s website at www.cnrl.com

## MANAGEMENT'S DISCUSSION AND ANALYSIS

### Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "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, the construction and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market 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, 2014 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2013.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the period ended March 31, 2014 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 and depreciation, depletion and amortization are 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 SCO.

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, 2014 in relation to the first quarter of 2013 and the fourth quarter of 2013. 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, 2013, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated May 8, 2014.

## FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Product sales | **$ 4,968** | $ 4,330 | $ 4,101 |
| Net earnings | **$ 622** | $ 413 | $ 213 |
| Per common share – basic | **$ 0.57** | $ 0.38 | $ 0.19 |
| – diluted | **$ 0.57** | $ 0.38 | $ 0.19 |
| Adjusted net earnings from operations [1] | **$ 921** | $ 563 | $ 401 |
| Per common share – basic | **$ 0.85** | $ 0.52 | $ 0.37 |
| – diluted | **$ 0.85** | $ 0.52 | $ 0.37 |
| Cash flow from operations [2] | **$ 2,146** | $ 1,782 | $ 1,571 |
| Per common share – basic | **$ 1.97** | $ 1.64 | $ 1.44 |
| – diluted | **$ 1.97** | $ 1.64 | $ 1.44 |
| Capital expenditures, net of dispositions | **$ 1,893** | $ 2,091 | $ 1,736 |

*(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 2014*** | *Dec 31 2013* | *Mar 31 2013* |
| *Net earnings as reported* | ***$ 622*** | *$ 413* | *$ 213* |
| *Share-based compensation, net of tax [1]* | ***143*** | *65* | *71* |
| *Unrealized risk management loss (gain), net of tax [2]* | ***38*** | *(26)* | *51* |
| *Unrealized foreign exchange loss, net of tax [3]* | ***118*** | *111* | *78* |
| *Realized foreign exchange gain on repayment of US dollar debt securities, net of tax [4]* | ***–*** | *–* | *(12)* |
| *Adjusted net earnings from operations* | ***$ 921*** | *$ 563* | *$ 401* |

*(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 Company's 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% notes.*

***Cash Flow from Operations***

| | Three Months Ended | | |
|---|---|---|---|
| *($ millions)* | ***Mar 31 2014*** | *Dec 31 2013* | *Mar 31 2013* |
| *Net earnings* | ***$ 622*** | *$ 413* | *$ 213* |
| *Non-cash items:* | | | |
| *Depletion, depreciation and amortization* | ***1,011*** | *1,272* | *1,142* |
| *Share-based compensation* | ***143*** | *65* | *71* |
| *Asset retirement obligation accretion* | ***45*** | *46* | *42* |
| *Unrealized risk management loss (gain)* | ***49*** | *(30)* | *62* |
| *Unrealized foreign exchange loss* | ***118*** | *111* | *78* |
| *Realized foreign exchange gain on repayment of US dollar debt securities* | ***–*** | *–* | *(12)* |
| *Equity loss from joint venture* | ***1*** | *1* | *2* |
| *Deferred income tax expense (recovery)* | ***157*** | *(96)* | *(27)* |
| *Cash flow from operations* | ***$ 2,146*** | *$ 1,782* | *$ 1,571* |

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

Net earnings for the first quarter of 2014 were $622 million compared with $213 million for the first quarter of 2013 and $413 million for the fourth quarter of 2013. Net earnings for the first quarter of 2014 included net after-tax expenses of $299 million compared with $188 million for the first quarter of 2013 and $150 million for the fourth quarter of 2013 related to the effects of share-based compensation, risk management activities, and fluctuations in foreign exchange rates including the impact of a realized foreign exchange gain on repayment of long-term debt. Excluding these items, adjusted net earnings from operations for the first quarter of 2014 were $921 million compared with $401 million for the first quarter of 2013 and $563 million for the fourth quarter of 2013.

The increase in adjusted net earnings for the first quarter of 2014 from the first quarter of 2013 was primarily due to:

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

partially offset by:

- lower crude oil sales volumes in the Offshore Africa segment.

The increase in adjusted net earnings for the first quarter of 2014 from the fourth quarter of 2013 was primarily due to:

- higher crude oil and NGLs and natural gas netbacks in the North America segment;
- higher realized SCO prices;
- lower depletion, depreciation and amortization expense; and
- the impact of a weaker Canadian dollar relative to the US dollar;

partially offset by:

- lower crude oil sales volumes in the Offshore Africa segment.

The impacts of share-based compensation, risk management activities and fluctuations 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 2014 was $2,146 million compared with $1,571 million for the first quarter of 2013 and $1,782 million for the fourth quarter of 2013. The fluctuations in cash flow from operations from the comparable periods were 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 2014 averaged 684,647 BOE/d and was comparable with the first quarter of 2013 and increased 1% from 677,242 BOE/d for the fourth quarter of 2013.

## 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 2014** | Dec 31 2013 | Sep 30 2013 | Jun 30 2013 |
|---|---|---|---|---|
| Product sales | **$ 4,968** | $ 4,330 | $ 5,284 | $ 4,230 |
| Net earnings | **$ 622** | $ 413 | $ 1,168 | $ 476 |
| Net earnings per common share | | | | |
| – basic | **$ 0.57** | $ 0.38 | $ 1.07 | $ 0.44 |
| – diluted | **$ 0.57** | $ 0.38 | $ 1.07 | $ 0.44 |

| ($ 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 |

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 the 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 strong heavy crude oil drilling program, and the impact of the turnaround/suspension and subsequent 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 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, and the turnaround/suspension and subsequent 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, fluctuations in depletion, depreciation and amortization expense in the North Sea due to the planned decommissioning of the Murchison platform, and the impact of the turnaround/suspension and subsequent 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.
- **Gains on corporate acquisition/disposition of properties** – Fluctuations due to the recognition of gains on corporate acquisitions/dispositions in the third quarter of 2013.

## BUSINESS ENVIRONMENT

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| WTI benchmark price (US$/bbl) | **$ 98.61** | $ 97.50 | $ 94.34 |
| Dated Brent benchmark price (US$/bbl) | **$ 108.20** | $ 109.29 | $ 112.43 |
| WCS blend differential from WTI (US$/bbl) | **$ 23.27** | $ 32.21 | $ 31.79 |
| WCS blend differential from WTI (%) | **24%** | 33% | 34% |
| SCO price (US$/bbl) | **$ 96.45** | $ 88.37 | $ 95.24 |
| Condensate benchmark price (US$/bbl) | **$ 102.53** | $ 94.30 | $ 107.18 |
| NYMEX benchmark price (US$/MMBtu) | **$ 4.89** | $ 3.63 | $ 3.35 |
| AECO benchmark price (C$/GJ) | **$ 4.52** | $ 2.99 | $ 2.92 |
| US/Canadian dollar average exchange rate (US$) | **$ 0.9064** | $ 0.9529 | $ 0.9917 |

### Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$98.61 per bbl for the first quarter of 2014, an increase of 5% from US$94.34 per bbl for the first quarter of 2013, and was comparable with the fourth quarter of 2013.

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$108.20 per bbl for the first quarter of 2014, a decrease of 4% from US$112.43 per bbl for the first quarter of 2013, and was comparable with the fourth quarter of 2013.

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. The Brent differential from WTI tightened for the first quarter of 2014 from the comparable periods in 2013 due to a continued debottlenecking of logistical constraints from Cushing to the US Gulf Coast.

The WCS Heavy Differential averaged 24% for the first quarter of 2014, compared with 34% for the first quarter of 2013, and 33% for the fourth quarter of 2013. The WCS Heavy Differential tightened in the first quarter of 2014 from the comparable periods due to the reinstatement of third party refinery operations, increased demand as a result of third party refinery expansion and higher refinery utilization in the first quarter of 2014. To partially mitigate its exposure to fluctuating heavy crude oil differentials, as at March 31, 2014, the Company entered into physical crude oil sales contracts with weighted average fixed WCS differentials as follows: 10,000 bbl/d in the second quarter of 2014 at US$21.69 per bbl; and 10,000 bbl/d in the third and fourth quarters of 2014 at US$20.81 per bbl. Subsequent to March 31, 2014, the WCS Heavy Differential narrowed in April 2014 to average US$22.47 per bbl and in May 2014 to average US$19.07 per bbl.

The SCO price averaged US$96.45 per bbl for the first quarter of 2014, comparable with the first quarter of 2013, and increased 9% from US$88.37 per bbl for the fourth quarter of 2013. The increase in SCO pricing for the first quarter of 2014 from the fourth quarter of 2013 was primarily due to an increase in demand as well as tightening differentials from WTI benchmark pricing as a result of pipeline constraints being alleviated from Cushing to the US Gulf Coast.

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$4.89 per MMBtu for the first quarter of 2014, an increase of 46% from US$3.35 per MMBtu for the first quarter of 2013, and an increase of 35% from US$3.63 per MMBtu for the fourth quarter of 2013.

AECO natural gas prices for the first quarter of 2014 averaged $4.52 per GJ, an increase of 55% from $2.92 per GJ for the first quarter of 2013, and an increase of 51% from $2.99 per GJ for the fourth quarter of 2013.

Natural gas prices increased for the first quarter of 2014 from the comparable periods due to increased winter weather related natural gas demand. The colder than normal winter resulted in natural gas storage inventories falling to below five-year lows in the US and Canada as at March 31, 2014.

**DAILY PRODUCTION, before royalties**

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| **Crude oil and NGLs** (bbl/d) | | | |
| North America – Exploration and Production | **348,187** | 332,231 | 345,489 |
| North America – Oil Sands Mining and Upgrading | **113,095** | 112,273 | 108,782 |
| North Sea | **16,715** | 20,155 | 18,774 |
| Offshore Africa | **10,791** | 13,379 | 16,112 |
| | **488,788** | 478,038 | 489,157 |
| **Natural gas** (MMcf/d) | | | |
| North America | **1,147** | 1,165 | 1,125 |
| North Sea | **7** | 7 | 1 |
| Offshore Africa | **21** | 23 | 24 |
| | **1,175** | 1,195 | 1,150 |
| **Total barrels of oil equivalent** (BOE/d) | **684,647** | 677,242 | 680,844 |
| **Product mix** | | | |
| Light and medium crude oil and NGLs | **15%** | 16% | 15% |
| Pelican Lake heavy crude oil | **7%** | 7% | 5% |
| Primary heavy crude oil | **20%** | 20% | 20% |
| Bitumen (thermal oil) | **12%** | 11% | 16% |
| Synthetic crude oil | **17%** | 17% | 16% |
| Natural gas | **29%** | 29% | 28% |
| **Percentage of product sales** (1) (excluding Midstream revenue) | | | |
| Crude oil and NGLs | **86%** | 89% | 89% |
| Natural gas | **14%** | 11% | 11% |

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

**DAILY PRODUCTION, net of royalties**

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| **Crude oil and NGLs** (bbl/d) | | | |
| North America – Exploration and Production | **280,826** | 285,594 | 289,992 |
| North America – Oil Sands Mining and Upgrading | **106,891** | 106,358 | 104,203 |
| North Sea | **16,662** | 20,106 | 18,706 |
| Offshore Africa | **9,762** | 11,351 | 13,603 |
| | **414,141** | 423,409 | 426,504 |
| **Natural gas** (MMcf/d) | | | |
| North America | **1,017** | 1,101 | 1,092 |
| North Sea | **7** | 7 | 1 |
| Offshore Africa | **18** | 19 | 20 |
| | **1,042** | 1,127 | 1,113 |
| **Total barrels of oil equivalent** (BOE/d) | **587,737** | 611,245 | 612,062 |

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

Crude oil and NGLs production for the first quarter of 2014 averaged 488,788 bbl/d, comparable with the first quarter of 2013 and increased 2% from 478,038 bbl/d for the fourth quarter of 2013. The increase in production for the first quarter of 2014 from the fourth quarter of 2013 was due to increased production in the North America segment, primarily related to the impact of a strong heavy crude oil drilling program, as well as the impact of strong and reliable production in Horizon, partially offset by lower production in North Sea and Offshore Africa. Crude oil and NGLs production in the first quarter of 2014 was within the Company's previously issued guidance of 469,000 to 495,000 bbl/d.

Natural gas production for the first quarter of 2014 increased 2% to 1,175 MMcf/d from 1,150 MMcf/d for the first quarter of 2013 and decreased 2% from 1,195 MMcf/d for the fourth quarter of 2013. The increase in natural gas production from the first quarter of 2013 was primarily a result of the completion of the Septimus drilling program and plant facility expansion in the third quarter of 2013, as well as the completion of minor acquisitions during 2013. The decrease in natural gas production from the fourth quarter of 2013 was primarily a result of normal production declines as the Company allocated capital to higher return crude oil projects. Natural gas production in the first quarter of 2014 was within the Company's previously issued guidance of 1,166 to 1,186 MMcf/d.

For 2014, annual production guidance is targeted to average between 537,000 and 574,000 bbl/d of crude oil and NGLs and between 1,530 and 1,570 MMcf/d of natural gas. Second quarter 2014 production guidance is targeted to average between 519,000 and 546,000 bbl/d of crude oil and NGLs and between 1,620 and 1,660 MMcf/d of natural gas.

**North America – Exploration and Production**

For the first quarter of 2014, crude oil and NGLs production averaged 348,187 bbl/d, comparable with the first quarter of 2013 and increased 5% from 332,231 bbl/d for the fourth quarter of 2013. The increase for the first quarter of 2014 from the fourth quarter of 2013 reflected strong production growth across the asset base, including heavy crude oil. First quarter 2014 production of crude oil and NGLs was within the Company's previously issued guidance of 335,000 to 351,000 bbl/d. Second quarter 2014 production guidance is targeted to average between 378,000 and 396,000 bbl/d for crude oil and NGLs.

Natural gas production increased 2% to 1,147 MMcf/d for the first quarter of 2014 compared with 1,125 MMcf/d in the first quarter of 2013 and decreased 2% from 1,165 MMcf/d for the fourth quarter of 2013. The increase in natural gas production for the first quarter of 2014 from the first quarter of 2013 was primarily a result of the completion of the Septimus drilling program and plant facility expansion in the third quarter of 2013, as well as the completion of minor acquisitions during 2013. The decrease in natural gas production from the fourth quarter of 2013 was primarily a result of normal production declines as the Company allocated capital to higher return crude oil projects.

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

For the first quarter of 2014, SCO production increased 4% to 113,095 bbl/d from 108,782 bbl/d for the first quarter of 2013 and increased 1% from 112,273 bbl/d for the fourth quarter of 2013. Production increased for the first quarter of 2014 from the comparable periods, reflecting a continued focus on reliable and efficient operations. First quarter 2014 production of SCO was within the Company's previously issued guidance of 108,000 to 115,000 bbl/d. Second quarter 2014 production guidance is targeted to average between 114,000 and 119,000 bbl/d.

**North Sea**

First quarter 2014 crude oil production decreased 11% to 16,715 bbl/d from 18,774 bbl/d for the first quarter of 2013, and decreased 17% from 20,155 bbl/d for the fourth quarter of 2013. The decrease in production for the first quarter of 2014 from the comparable periods was primarily due to the cessation of production of approximately 1,300 bbl/d related to the planned decommissioning of the Murchison platform, unplanned downtime on the Tiffany platform, and natural field declines in other North Sea fields. The Company commenced drilling in the Ninian field late in the fourth quarter of 2013 with expected production in the second quarter of 2014.

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 has been repaired, is back in the field and is currently being tied in to the subsea system, with production targeted early in the third quarter of 2014.

**Offshore Africa**

First quarter 2014 crude oil production averaged 10,791 bbl/d, decreasing 33% from 16,112 bbl/d for the first quarter of 2013 and decreasing 19% from 13,379 bbl/d for the fourth quarter of 2013. The decrease in production volumes for the first quarter of 2014 was due to a temporary shut in of the Baobab field in December 2013 due to a FPSO mooring line failure and natural field declines. Turnaround activities were advanced into this timeframe and production in the Baobab field was reinstated in late January 2014. The Company successfully completed the permanent repairs on the mooring lines in March 2014.

**International Guidance**

The Company's North Sea and Offshore Africa first quarter 2014 crude oil production was 27,506 bbl/d and was within the Company's previously issued guidance of 26,000 to 29,000 bbl/d. Second quarter 2014 production guidance is targeted to average between 27,000 and 31,000 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 2014** | Dec 31 2013 | Mar 31 2013 |
|---|---|---|---|
| North America – Exploration and Production | **1,069,537** | 830,673 | 811,181 |
| North America – Oil Sands Mining and Upgrading (SCO) | **1,693,887** | 1,550,857 | 1,334,054 |
| North Sea | **311,457** | 385,073 | 409,333 |
| Offshore Africa | **1,156,700** | 185,476 | 829,793 |
| | **4,231,581** | 2,952,079 | 3,384,361 |

## OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| **Crude oil and NGLs** ($/bbl) (1) | | | |
| Sales price (2) | **$ 79.68** | $ 69.38 | $ 60.87 |
| Transportation | **2.49** | 1.84 | 2.37 |
| Realized sales price, net of transportation | **77.19** | 67.54 | 58.50 |
| Royalties | **14.05** | 8.82 | 8.76 |
| Production expense | **19.18** | 18.59 | 17.56 |
| Netback | **$ 43.96** | $ 40.13 | $ 32.18 |
| **Natural gas** ($/Mcf) (1) | | | |
| Sales price (2) | **$ 5.69** | $ 3.62 | $ 3.51 |
| Transportation | **0.30** | 0.28 | 0.29 |
| Realized sales price, net of transportation | **5.39** | 3.34 | 3.22 |
| Royalties | **0.62** | 0.21 | 0.12 |
| Production expense | **1.61** | 1.37 | 1.53 |
| Netback | **$ 3.16** | $ 1.76 | $ 1.57 |
| **Barrels of oil equivalent** ($/BOE) (1) | | | |
| Sales price (2) | **$ 63.14** | $ 53.30 | $ 47.90 |
| Transportation | **2.29** | 1.83 | 2.21 |
| Realized sales price, net of transportation | **60.85** | 51.47 | 45.69 |
| Royalties | **10.42** | 6.23 | 6.05 |
| Production expense | **15.82** | 15.04 | 14.74 |
| Netback | **$ 34.61** | $ 30.20 | $ 24.90 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*
*(2) Net of blending costs and excluding risk management activities.*

## PRODUCT PRICES – EXPLORATION AND PRODUCTION

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| **Crude oil and NGLs** ($/bbl) (1) (2) | | | |
| North America | **$ 77.54** | $ 62.70 | $ 55.68 |
| North Sea | **$ 121.38** | $ 113.84 | $ 114.28 |
| Offshore Africa | **$ –** | $ 108.25 | $ 113.70 |
| Company average | **$ 79.68** | $ 69.38 | $ 60.87 |
| **Natural gas** ($/Mcf) (1) (2) | | | |
| North America | **$ 5.56** | $ 3.46 | $ 3.37 |
| North Sea | **$ 6.05** | $ 5.05 | $ 3.65 |
| Offshore Africa | **$ 12.18** | $ 11.13 | $ 10.24 |
| Company average | **$ 5.69** | $ 3.62 | $ 3.51 |
| **Company average** ($/BOE) (1) (2) | **$ 63.14** | $ 53.30 | $ 47.90 |

*(1) Amounts expressed on a per unit basis are based on sales volumes.*
*(2) Net of blending costs and excluding risk management activities.*

### North America

North America realized crude oil prices averaged $77.54 per bbl for the first quarter of 2014 and increased 39% compared with $55.68 per bbl for the first quarter of 2013 and increased 24% compared with $62.70 per bbl for the fourth quarter of 2013. The increase in realized crude oil prices for the first quarter of 2014 from the comparable periods was due to higher WTI benchmark pricing, tightening WCS Heavy Differentials and the impact of a weaker Canadian dollar relative to the US dollar. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2014 contributed approximately 172,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 65% to average $5.56 per Mcf for the first quarter of 2014 compared with $3.37 per Mcf in the first quarter of 2013, and increased 61% compared with $3.46 per Mcf for the fourth quarter of 2013. The increase in realized natural gas prices for the first quarter of 2014 from the comparable periods was primarily due to increased winter weather related natural gas demand resulting in natural gas storage inventories falling to below five-year lows in the US and Canada as at March 31, 2014.

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

| (Quarterly Average) | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
|---|---|---|---|
| **Wellhead Price** [1] [2] | | | |
| Light and medium crude oil and NGLs ($/bbl) | **$ 83.57** | $ 70.91 | $ 73.77 |
| Pelican Lake heavy crude oil ($/bbl) | **$ 79.94** | $ 60.19 | $ 54.41 |
| Primary heavy crude oil ($/bbl) | **$ 77.78** | $ 61.75 | $ 51.45 |
| Bitumen (thermal oil) ($/bbl) | **$ 69.73** | $ 57.97 | $ 50.42 |
| Natural gas ($/Mcf) | **$ 5.56** | $ 3.46 | $ 3.37 |

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

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

**North Sea**

Realized crude oil prices increased 6% to average $121.38 per bbl for the first quarter of 2014 from $114.28 per bbl for the first quarter of 2013, and increased 7% from $113.84 per bbl for the fourth quarter of 2013. The increase in realized crude oil prices for the first quarter of 2014 from the comparable periods was primarily the result of the timing of liftings and the impact of a weaker Canadian dollar relative to the US dollar.

**Offshore Africa**

Due to the timing of scheduled liftings from the various fields, the Company had no crude oil liftings during the first quarter of 2014. Accordingly, no crude oil revenue was recognized. Realized crude oil prices averaged $113.70 per bbl for the first quarter of 2013 and $108.25 per bbl for the fourth quarter of 2013.

## ROYALTIES – EXPLORATION AND PRODUCTION

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| **Crude oil and NGLs** ($/bbl) [1] | | | |
| North America | **$ 14.75** | $ 8.66 | $ 8.65 |
| North Sea | **$ 0.38** | $ 0.28 | $ 0.41 |
| Offshore Africa | **$ –** | $ 16.41 | $ 17.71 |
| Company average | **$ 14.05** | $ 8.82 | $ 8.76 |
| **Natural gas** ($/Mcf) [1] | | | |
| North America | **$ 0.60** | $ 0.17 | $ 0.09 |
| Offshore Africa | **$ 2.06** | $ 2.04 | $ 1.57 |
| Company average | **$ 0.62** | $ 0.21 | $ 0.12 |
| **Company average** ($/BOE) [1] | **$ 10.42** | $ 6.23 | $ 6.05 |

*(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 first quarter of 2014 reflected movements in benchmark commodity prices and the fluctuations of the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 20% of product sales for the first quarter of 2014 compared with 16% for the first quarter of 2013 and 14% for the fourth quarter of 2013. The increase in royalties in the first quarter of 2014 from the comparable periods was primarily due to the increase in realized crude oil prices. Crude oil and NGLs royalties per bbl are anticipated to average 19% to 21% of product sales for 2014.

Natural gas royalties averaged approximately 11% of product sales for the first quarter of 2014 compared with 3% for the first quarter of 2013 and 5% for the fourth quarter of 2013. The increase in natural gas royalty rates in the first quarter of 2014 from the comparable periods was primarily due to the increase in realized natural gas prices. Natural gas royalties are anticipated to average 10% to 11% of product sales for 2014.

### 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 17% for the first quarter of 2014 and related to natural gas sales only. Royalty rates as a percentage of product sales averaged approximately 16% for the first quarter of 2013 and 15% for the fourth quarter of 2013.

Offshore Africa royalty rates are anticipated to average 4.5% to 6.5% of product sales for 2014.

## PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| **Crude oil and NGLs** ($/bbl) (1) | | | |
| North America | **$ 16.31** | $ 14.46 | $ 14.61 |
| North Sea | **$ 75.51** | $ 65.41 | $ 74.65 |
| Offshore Africa | **$ –** | $ 29.31 | $ 25.72 |
| Company average | **$ 19.18** | $ 18.59 | $ 17.56 |
| **Natural gas** ($/Mcf) (1) | | | |
| North America | **$ 1.54** | $ 1.32 | $ 1.52 |
| North Sea | **$ 5.83** | $ 4.81 | $ 3.77 |
| Offshore Africa | **$ 3.64** | $ 2.73 | $ 2.24 |
| Company average | **$ 1.61** | $ 1.37 | $ 1.53 |
| **Company average** ($/BOE) (1) | **$ 15.82** | $ 15.04 | $ 14.74 |

*(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 2014 increased 12% to $16.31 per bbl from $14.61 per bbl for the first quarter of 2013 and increased 13% from $14.46 per bbl for the fourth quarter of 2013. The increase in production expense for the first quarter of 2014 from the comparable periods was primarily the result of higher energy costs, as well as higher servicing costs related to heavy oil activities, and cyclic timing of thermal oil production. North America crude oil and NGLs production expense is anticipated to average $13.00 to $15.00 per bbl for 2014.

North America natural gas production expense for the first quarter of 2014 averaged $1.54 per Mcf, comparable with the first quarter of 2013 and increased 17% from $1.32 per Mcf for the fourth quarter of 2013. Natural gas production expense increased for the first quarter of 2014 from the fourth quarter of 2013 due to lower production volumes along with the impact of seasonal conditions. North America natural gas production expense is anticipated to average $1.35 to $1.45 per Mcf for 2014.

### North Sea

North Sea crude oil production expense for the first quarter of 2014 averaged $75.51 per bbl, comparable with the first quarter of 2013 and increased 15% from $65.41 per bbl for the fourth quarter of 2013. Production expense increased on a per barrel basis from the fourth quarter of 2013 due to the impact of the cessation of production from the Murchison platform in the first quarter of 2014, production declines on relatively fixed costs in other North Sea fields and the impact of a weaker Canadian dollar. North Sea crude oil production expense is anticipated to average $60.00 to $64.00 per bbl for 2014 as new drilling activities are expected to result in additional production from the Ninian fields, and as the Banff FPSO is targeted to return to service early in the third quarter of 2014.

### Offshore Africa

As there were no crude oil liftings during the first quarter of 2014, no crude oil production expense was recognized during the first quarter of 2014. Offshore Africa crude oil production expense averaged $25.72 per bbl for the first quarter of 2013 and $29.31 per bbl for the fourth quarter of 2013. Offshore Africa crude oil production expense is anticipated to average $38.50 to $42.50 per bbl for 2014 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 2014** | Dec 31 2013 | Mar 31 2013 |
| Expense ($ millions) | **$ 879** | $ 1,133 | $ 1,023 |
| $/BOE (1) | **$ 17.55** | $ 21.20 | $ 19.99 |

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

Depletion, depreciation and amortization expense decreased for the first quarter of 2014 from the comparable periods due to the increase in the North America proved reserves, lower sales volumes in Offshore Africa and lower depletion, depreciation and amortization expense from the Murchison field in the North Sea due to the cessation of production.

## ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Expense ($ millions) | **$ 33** | $ 38 | $ 34 |
| $/BOE (1) | **$ 0.67** | $ 0.71 | $ 0.66 |

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

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

## OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

## OPERATIONS UPDATE

During the first quarter of 2014 the Company continued to focus on reliable and efficient operations, leading to production of 113,095 bbl/d, which was within stated guidance.

## PRODUCT PRICES, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

| | Three Months Ended | | |
|---|---|---|---|
| ($/bbl) (1) | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| SCO sales price | **$ 107.82** | $ 92.05 | $ 96.19 |
| Bitumen value for royalty purposes (2) | **$ 66.27** | $ 55.45 | $ 60.47 |
| Bitumen royalties (3) | **$ 5.06** | $ 5.06 | $ 3.81 |
| Transportation | **$ 1.96** | $ 1.51 | $ 1.58 |

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

Realized SCO sales prices averaged $107.82 per bbl for the first quarter of 2014, an increase of 12% compared with $96.19 per bbl for the first quarter of 2013 and an increase of 17% compared with $92.05 per bbl for the fourth quarter of 2013, reflecting benchmark pricing, prevailing differentials and the impact of a weaker Canadian dollar relative to the US dollar.

## 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.

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions) | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Cash production costs, excluding natural gas costs | **$ 375** | $ 362 | $ 349 |
| Natural gas costs | **37** | 27 | 28 |
| Total cash production costs | **$ 412** | $ 389 | $ 377 |

| | Three Months Ended | | |
|---|---|---|---|
| ($/bbl) (1) | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Cash production costs, excluding natural gas costs | **$ 37.39** | $ 36.31 | $ 36.95 |
| Natural gas costs | **3.72** | 2.74 | 2.98 |
| Total cash production costs | **$ 41.11** | $ 39.05 | $ 39.93 |
| Sales (bbl/d) | **111,506** | 108,163 | 105,000 |

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

Cash production costs for the first quarter of 2014 averaged $41.11 per bbl, an increase of 3% compared with $39.93 per bbl for the first quarter of 2013 and an increase of 5% compared with $39.05 per bbl for the fourth quarter of 2013 primarily reflecting higher energy costs including natural gas and mine diesel fuel. Cash production costs are anticipated to average $36.00 to $39.00 per bbl for 2014.

## DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions) | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Depletion, depreciation and amortization | **$ 130** | $ 137 | $ 117 |
| $/bbl (1) | **$ 12.95** | $ 13.75 | $ 12.35 |

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

Depletion, depreciation and amortization expense for the first quarter of 2014 increased compared to the first quarter of 2013 due to higher sales volumes. Depletion, depreciation and amortization expense for the first quarter of 2014 was comparable to the fourth quarter of 2013.

## ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions) | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Expense | **$ 12** | $ 8 | $ 8 |
| $/bbl (1) | **$ 1.17** | $ 0.85 | $ 0.90 |

*(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 2014 | Dec 31 2013 | Mar 31 2013 |
|---|---|---|---|
| Revenue | **$ 31** | $ 26 | $ 27 |
| Production expense | **9** | 8 | 8 |
| Midstream cash flow | **22** | 18 | 19 |
| Depreciation | **2** | 2 | 2 |
| Equity loss from joint venture | **1** | 1 | 2 |
| Segment earnings before taxes | **$ 19** | $ 15 | $ 15 |

Midstream operating results were consistent with the comparable periods.

The Company has a 50% interest in the North West Redwater Partnership ("Redwater Partnership"). Redwater Partnership has entered into agreements 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 ("APMC"), 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 Partnership and its partners.

As at March 31, 2014, Redwater Partnership had interim borrowings of $955 million under credit facilities totaling $1,200 million maturing on November 28, 2014. These facilities are secured by a floating charge on the assets of Redwater Partnership with a mandatory repayment required from future financing proceeds. At maturity or at such later date as mutually agreed to by the lenders and Redwater Partnership, the Company will be obligated to repay its 25% pro rata share of any amount outstanding under the facility. As at May 7, 2014, interim borrowings under the facilities were $883 million.

In April 2014, Redwater Partnership, the Company and APMC amended certain terms of the processing agreements. In conjunction with these amendments, the Company, along with APMC, each committed to provide additional funding up to $350 million to attain Project completion based on the revised Project cost estimate of approximately $8,500 million. The additional funding is to be in the form of subordinated debt bearing interest at prime plus 6%, which is anticipated to form part of the equity toll. As at May 7, 2014, the Company and APMC had each provided $113 million of funding of subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

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

## ADMINISTRATION EXPENSE

| ($ millions) | Three Months Ended Mar 31 2014 | Dec 31 2013 | Mar 31 2013 |
|---|---|---|---|
| Expense | **$ 90** | $ 93 | $ 79 |
| $/BOE (1) | **$ 1.49** | $ 1.47 | $ 1.30 |

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

Administration expense for the first quarter of 2014 increased from the first quarter of 2013 primarily due to higher staffing and general corporate costs, and was comparable with the fourth quarter of 2013.

## SHARE-BASED COMPENSATION

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions) | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Expense | **$ 143** | $ 65 | $ 71 |

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

The Company recorded a $143 million share-based compensation expense for the three months ended March 31, 2014, 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, 2014, the Company capitalized $26 million of share-based compensation expense to property, plant and equipment in the Oil Sands Mining and Upgrading segment (March 31, 2013 – $11 million expense).

For the three months ended March 31, 2014, the Company paid $4 million for stock options surrendered for cash settlement (March 31, 2013 – $1 million).

## INTEREST AND OTHER FINANCING EXPENSE

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions, except per BOE amounts) | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Expense, gross | **$ 115** | $ 113 | $ 113 |
| Less: capitalized interest | **47** | 53 | 36 |
| Expense, net | **$ 68** | $ 60 | $ 77 |
| $/BOE (1) | **$ 1.13** | $ 0.94 | $ 1.27 |
| Average effective interest rate | **4.3%** | 4.4% | 4.5% |

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

Gross interest and other financing expense for the first quarter of 2014 was consistent with the comparable periods. Capitalized interest of $47 million for the three months ended March 31, 2014 was primarily related to the Horizon Phase 2/3 expansion.

The Company's average effective interest rate for first quarter of 2014 decreased from the first quarter of 2013 primarily due to an increase in the utilization of the lower cost US commercial paper program that was implemented in March 2013 as well as the repayment of $400 million of 4.50% medium-term notes and US$400 million of 5.15% notes during the first quarter of 2013. The Company's average effective interest rate for the first quarter of 2014 was comparable with the fourth quarter of 2013.

## RISK MANAGEMENT ACTIVITIES

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

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions) | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Crude oil and NGLs financial instruments | **$ –** | $ 5 | $ – |
| Foreign currency contracts | **(75)** | (41) | (83) |
| Realized gain | **(75)** | (36) | (83) |
| | | | |
| Crude oil and NGLs financial instruments | **(3)** | (10) | 24 |
| Natural gas financial instruments | **45** | (5) | – |
| Foreign currency contracts | **7** | (15) | 38 |
| Unrealized loss (gain) | **49** | (30) | 62 |
| Net gain | **$ (26)** | $ (66) | $ (21) |

Complete details related to outstanding derivative financial instruments at March 31, 2014 are disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

The Company recorded a net unrealized loss of $49 million ($38 million after-tax) on its risk management activities for the three months ended March 31, 2014 (December 31, 2013 – unrealized gain of $30 million; $26 million after-tax; March 31, 2013 – unrealized loss of $62 million; $51 million after-tax).

## FOREIGN EXCHANGE

| | Three Months Ended | | |
|---|---|---|---|
| ($ millions) | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Net realized (gain) loss | **$ (1)** | $ 3 | $ (32) |
| Net unrealized loss [1] | **118** | 111 | 78 |
| Net loss | **$ 117** | $ 114 | $ 46 |

*(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, 2014 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange loss for the three months ended March 31, 2014 was primarily related to the impact of a weaker Canadian dollar with respect to US dollar debt. The net unrealized loss for each of the periods presented included the impact of cross currency swaps (three months ended March 31, 2014 – unrealized gain of $100 million, December 31, 2013 – unrealized gain of $85 million, March 31, 2013 – unrealized gain of $49 million). The US/Canadian dollar exchange rate at March 31, 2014 was US$0.9047 (December 31, 2013 – US$0.9402; March 31, 2013 – US$0.9846).

## INCOME TAXES

| ($ millions, except income tax rates) | Three Months Ended<br>**Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
|---|---|---|---|
| North America (1) | **$ 192** | $ 133 | $ 122 |
| North Sea | **(15)** | 5 | (7) |
| Offshore Africa | **4** | 55 | 35 |
| PRT (recovery) expense– North Sea | **(61)** | 5 | (13) |
| Other taxes | **6** | 4 | 4 |
| Current income tax expense | **126** | 202 | 141 |
| Deferred income tax expense (recovery) | **91** | (36) | (4) |
| Deferred PRT expense (recovery) – North Sea | **66** | (60) | (23) |
| Deferred income tax expense (recovery) | **157** | (96) | (27) |
| | **$ 283** | $ 106 | $ 114 |
| Effective income tax rate on adjusted net earnings from operations (2) | **23.5%** | 21.4% | 28.1% |

*(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 2014, based on forward commodity prices and the current availability of tax pools, the Company expects to incur current income tax expense of $950 million to $1,050 million in Canada and recoveries of $95 million to $115 million in the North Sea and Offshore Africa.

## NET CAPITAL EXPENDITURES [1]

| ($ millions) | Three Months Ended Mar 31 2014 | Dec 31 2013 | Mar 31 2013 |
|---|---|---|---|
| **Exploration and Evaluation** | | | |
| Net expenditures | **$ 117** | $ 7 | $ 77 |
| **Property, Plant and Equipment** | | | |
| Net property acquisitions | **(4)** | 61 | 11 |
| Well drilling, completion and equipping | **641** | 600 | 555 |
| Production and related facilities | **415** | 444 | 537 |
| Capitalized interest and other [2] | **23** | 34 | 28 |
| Net expenditures | **1,075** | 1,139 | 1,131 |
| **Total Exploration and Production** | **1,192** | 1,146 | 1,208 |
| **Oil Sands Mining and Upgrading** | | | |
| Horizon Phase 2/3 construction costs | **444** | 597 | 355 |
| Sustaining capital | **60** | 28 | 51 |
| Turnaround costs | **2** | 2 | 17 |
| Capitalized interest and other [2] | **73** | 56 | 38 |
| **Total Oil Sands Mining and Upgrading** | **579** | 683 | 461 |
| **Midstream** | **25** | 185 | 5 |
| **Abandonments** [3] | **87** | 71 | 55 |
| **Head office** | **10** | 6 | 7 |
| **Total net capital expenditures** | **$ 1,893** | $ 2,091 | $ 1,736 |
| **By segment** | | | |
| North America | **$ 1,087** | $ 1,001 | $ 1,093 |
| North Sea | **88** | 95 | 85 |
| Offshore Africa | **17** | 50 | 30 |
| Oil Sands Mining and Upgrading | **579** | 683 | 461 |
| Midstream | **25** | 185 | 5 |
| Abandonments [3] | **87** | 71 | 55 |
| Head office | **10** | 6 | 7 |
| **Total** | **$ 1,893** | $ 2,091 | $ 1,736 |

*(1) 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 2014 were $1,893 million compared with $1,736 million for the first quarter of 2013 and $2,091 million for the fourth quarter of 2013.

The increase in capital expenditures for the first quarter of 2014 from the first quarter of 2013 was primarily due to increased well drilling and completions spending as well as Horizon Phase 2/3 site construction activity partially offset by decreased production and related facilities spending. The decrease in capital expenditures for the first quarter of 2014 from the fourth quarter of 2013 was primarily due to reduced capital spending in Horizon Phase 2/3 site construction activity as well as lower Midstream pipeline activity, partially offset by higher exploration and evaluation activities in North America.

During the first quarter of 2014, the Company entered into an agreement to acquire certain producing Canadian crude oil and natural gas properties, together with undeveloped land. In connection with the agreement, the Company arranged an additional $1,000 million unsecured non-revolving bank credit facility maturing March 2016 and with terms similar to the Company's current syndicated credit facilities, available upon closing. Subsequently, the Company completed the acquisition of these properties on April 1, 2014, for preliminary cash consideration of approximately $3,092 million, subject to final closing adjustments.

**Drilling Activity (number of wells)**

| | Three Months Ended | | |
|---|---|---|---|
| | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
| Net successful natural gas wells | **25** | 11 | 15 |
| Net successful crude oil wells [1] | **271** | 324 | 300 |
| Dry wells | **3** | 13 | 5 |
| Stratigraphic test / service wells | **330** | 54 | 305 |
| Total | **629** | 402 | 625 |
| Success rate (excluding stratigraphic test / service wells) | **99%** | 96% | 98% |

*(1) Includes bitumen wells.*

**North America**

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 62% of the total capital expenditures for the three months ended March 31, 2014 compared with approximately 66% for the three months ended March 31, 2013.

During the first quarter of 2014, the Company targeted 25 net natural gas wells, including 11 wells in Northeast British Columbia, 13 wells in Northwest Alberta and 1 well in Northern Plains. The Company also targeted 274 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 224 primary heavy crude oil wells, 11 bitumen (thermal oil) wells and 1 light crude oil well were drilled. Another 38 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the first quarter of 2014 averaged approximately 82,000 bbl/d compared with approximately 109,000 bbl/d for the first quarter of 2013 and approximately 78,000 bbl/d for the fourth quarter of 2013. Production volumes were in line with expectations due to the cyclic nature of thermal oil production at Primrose and the ramp up of production at Kirby South.

In the second quarter of 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Company continues to work with the regulator on the causation review of the bitumen emulsion seepage. The Company's near term steaming plan at Primrose has been modified, with steaming being reduced in certain areas.

The next planned phase of the Company's in situ Oil Sands assets expansion is the Kirby South Project. Site construction is complete and first steam injection was achieved in September 2013. As at March 31, 2014, 25 well pairs had been fully converted to the production stage.

Development of the tertiary recovery conversion projects at Pelican Lake continued and 3 horizontal injection wells were drilled during the first quarter of 2014. Pelican Lake production averaged approximately 48,000 bbl/d for the first quarter of 2014 compared with 38,000 bbl/d for the first quarter of 2013 and 46,000 bbl/d for the fourth quarter of 2013.

In order to expand its pipeline infrastructure the Company has participated in the expansion of the Cold Lake pipeline with construction anticipated to be completed by 2016.

For the second quarter of 2014, the Company's overall planned drilling activity in North America is expected to be 139 net crude oil wells, 3 net bitumen wells and 14 net natural gas wells, excluding stratigraphic and service wells.

**Oil Sands Mining and Upgrading**

Phase 2/3 expansion activity in the first quarter of 2014 was focused on field construction of the gas recovery unit, sulphur recovery unit, butane treatment unit, coker expansion, tank farms, cooling water tower, tailings, hydrotransport, froth treatment, tailings pumphouse, and extraction trains 3 and 4, along with engineering related to the froth treatment plants, extraction retrofit of trains 1 and 2, hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit.

**North Sea**

The Company commenced drilling in the Ninian field late in the fourth quarter of 2013 with expected production in the second quarter of 2014. The decommissioning activities at the Murchison platform commenced in the fourth quarter of 2013 and the Company estimates the decommissioning efforts will continue for approximately 5 years.

**Offshore Africa**

During the fourth quarter of 2013, the Company contracted a drilling rig for a 6 gross well drilling program at the Baobab field in Côte d'Ivoire. This rig is expected to arrive in country no later than the first quarter of 2015. In April 2014, at the Espoir field, the Company contracted a drilling rig for a 10 gross well development drilling program to commence in the latter half of 2014.

Exploration activities continue to progress in both Côte d'Ivoire and South Africa. In Côte d'Ivoire, the operator in Block CI-514 commenced drilling 1 exploratory well in March 2014. Subsequently, the operator completed drilling and encountered the presence of light oil. The well was plugged and the data gathered will now be evaluated to determine the extent of the accumulation and the forward plan for appraisal. In South Africa, the operator is targeting to commence drilling 1 exploratory well in the third quarter of 2014.

## LIQUIDITY AND CAPITAL RESOURCES

| ($ millions, except ratios) | **Mar 31 2014** | Dec 31 2013 | Mar 31 2013 |
|---|---|---|---|
| Working capital deficit [1] | **$ 1,025** | $ 1,574 | $ 1,178 |
| Long-term debt [2] [3] | **$ 10,354** | $ 9,661 | $ 9,322 |
| | | | |
| Share capital | **$ 4,100** | $ 3,854 | $ 3,742 |
| Retained earnings | **22,193** | 21,876 | 20,564 |
| Accumulated other comprehensive income | **44** | 42 | 68 |
| Shareholders' equity | **$ 26,337** | $ 25,772 | $ 24,374 |
| | | | |
| Debt to book capitalization [3] [4] | **28%** | 27% | 28% |
| Debt to market capitalization [3] [5] | **18%** | 20% | 21% |
| After-tax return on average common shareholders' equity [6] | **11%** | 9% | 7% |
| After-tax return on average capital employed [3] [7] | **8%** | 7% | 6% |

*(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 expense for the twelve month trailing period; as a percentage of average capital employed for the period.*

At March 31, 2014, 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 annual MD&A for the year ended December 31, 2013. 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 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.

As at March 31, 2014, the Company had in place bank credit facilities of $5,803 million, of which $4,561 million, net of commercial paper issuances of $553 million, was available. Credit facilities at March 31, 2014 included a $1,000 million non-revolving term credit facility arranged in connection with the acquisition of certain producing Canadian crude oil and natural gas properties announced in the first quarter of 2014. On April 1, 2014, the Company completed the acquisition of the crude oil and natural gas properties for preliminary cash consideration of $3,092 million, before final purchase adjustments.

During the first quarter of 2014, the Company issued US$500 million of three-month LIBOR plus 0.375% notes due March 2016, and concurrently, entered into cross currency swaps to fix the foreign currency exchange rate risk at three-month CDOR plus 0.309% and $555 million. In addition, the Company issued US$500 million of 3.80% notes due April 2024. Proceeds from the securities were used to repay bank indebtedness. At March 31, 2014, the Company had maturities of long-term debt aggregating $945 million over the next 12 months (US$500 million due November 2014, US$350 million due December 2014).

Long-term debt was $10,354 million at March 31, 2014, resulting in a debt to book capitalization ratio of 28% (December 31, 2013 – 27%; March 31, 2013 – 28%). 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 operations 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 production for 2014 and 2015 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, 2014 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 7, 2014, an average of approximately 297,000 bbl/d of currently forecasted 2014 crude oil volumes and 50,000 bbl/d of currently forecasted 2015 crude oil volumes were hedged using price collars and physical crude oil sales contracts with fixed WCS differentials. An additional 500,000 MMBtu/d of natural gas volumes were hedged for April 2014 to October 2014 using AECO basis swaps and 200,000 GJ/d of natural gas volumes were hedged for April 2014 to December 2014 using price collars. Further details related to the Company's commodity derivative financial instruments outstanding at March 31, 2014 are discussed in note 13 to the Company's unaudited interim consolidated financial statements.

**Share Capital**

As at March 31, 2014, there were 1,092,120,000 common shares outstanding (March 31, 2013 – 1,092,264,000 common shares) and 68,304,000 stock options outstanding. As at May 7, 2014, the Company had 1,093,271,000 common shares outstanding and 66,377,000 stock options outstanding.

On March 5, 2014, the Company's Board of Directors approved an increase in the annual dividend to $0.90 per common share (previous annual dividend rate of $0.80 per common share), beginning with the quarterly dividend payable on April 1, 2014 at $0.225 per common share. This represents a 13% increase from the previous quarterly dividend, reflecting 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 2014, 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 2014 and ending April 2015, up to 54,596,899 common shares. The Company's Normal Course Issuer Bid announced in 2013 expired April 2014.

For the three months ended March 31, 2014, the Company purchased for cancellation 1,775,000 common shares at a weighted average price of $36.83 per common share, for a total cost of $65 million. Retained earnings were reduced by $59 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2014, the Company purchased 330,000 common shares at a weighted average price of $43.44 per common share for a total cost of $14 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, 2014:

| ($ millions) | Remaining 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter |
|---|---|---|---|---|---|---|
| Product transportation and pipeline | $ 238 | $ 307 | $ 238 | $ 212 | $ 176 | $ 1,324 |
| Offshore equipment operating leases and offshore drilling | $ 119 | $ 247 | $ 84 | $ 63 | $ 57 | $ 18 |
| Long-term debt (1) | $ 1,493 | $ 400 | $ 1,221 | $ 1,386 | $ 442 | $ 5,476 |
| Interest and other financing expense (2) | $ 367 | $ 432 | $ 408 | $ 349 | $ 300 | $ 4,032 |
| Office leases | $ 29 | $ 44 | $ 45 | $ 48 | $ 50 | $ 343 |
| Other | $ 239 | $ 173 | $ 72 | $ 1 | $ 1 | $ 1 |

*(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 expense 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, 2014.*

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 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, 2014.

## 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, 2013.

## CONSOLIDATED BALANCE SHEETS

| As at<br>(millions of Canadian dollars, unaudited) | Note | Mar 31<br>2014 | Dec 31<br>2013 |
|---|---|---|---|
| **ASSETS** | | | |
| **Current assets** | | | |
| Cash and cash equivalents | | **$ 19** | $ 16 |
| Accounts receivable | | **1,918** | 1,427 |
| Inventory | | **748** | 632 |
| Prepaids and other | | **174** | 141 |
| | | **2,859** | 2,216 |
| **Exploration and evaluation assets** | 3 | **2,680** | 2,609 |
| **Property, plant and equipment** | 4 | **47,299** | 46,487 |
| **Other long-term assets** | 5 | **410** | 442 |
| | | **$ 53,248** | $ 51,754 |
| **LIABILITIES** | | | |
| **Current liabilities** | | | |
| Accounts payable | | **$ 822** | $ 637 |
| Accrued liabilities | | **2,653** | 2,519 |
| Current income taxes | | **22** | 359 |
| Current portion of long-term debt | 6 | **1,498** | 1,444 |
| Current portion of other long-term liabilities | 7 | **387** | 275 |
| | | **5,382** | 5,234 |
| **Long-term debt** | 6 | **8,856** | 8,217 |
| **Other long-term liabilities** | 7 | **4,307** | 4,348 |
| **Deferred income taxes** | | **8,366** | 8,183 |
| | | **26,911** | 25,982 |
| **SHAREHOLDERS' EQUITY** | | | |
| **Share capital** | 9 | **4,100** | 3,854 |
| **Retained earnings** | | **22,193** | 21,876 |
| **Accumulated other comprehensive income** | 10 | **44** | 42 |
| | | **26,337** | 25,772 |
| | | **$ 53,248** | $ 51,754 |

*Commitments and contingencies (note 14).*

Approved by the Board of Directors on May 8, 2014

## CONSOLIDATED STATEMENTS OF EARNINGS

| (millions of Canadian dollars, except per common share amounts, unaudited) | Note | Three Months Ended Mar 31 2014 | Mar 31 2013 |
|---|---|---|---|
| Product sales | | **$ 4,968** | $ 4,101 |
| Less: royalties | | **(572)** | (346) |
| **Revenue** | | **4,396** | 3,755 |
| **Expenses** | | | |
| Production | | **1,211** | 1,135 |
| Transportation and blending | | **831** | 855 |
| Depletion, depreciation and amortization | 4 | **1,011** | 1,142 |
| Administration | | **90** | 79 |
| Share-based compensation | 7 | **143** | 71 |
| Asset retirement obligation accretion | 7 | **45** | 42 |
| Interest and other financing expense | | **68** | 77 |
| Risk management activities | 13 | **(26)** | (21) |
| Foreign exchange loss | | **117** | 46 |
| Equity loss from joint venture | 5 | **1** | 2 |
| | | **3,491** | 3,428 |
| **Earnings before taxes** | | **905** | 327 |
| Current income tax expense | 8 | **126** | 141 |
| Deferred income tax expense (recovery) | 8 | **157** | (27) |
| **Net earnings** | | **$ 622** | $ 213 |
| **Net earnings per common share** | | | |
| Basic | 12 | **$ 0.57** | $ 0.19 |
| Diluted | 12 | **$ 0.57** | $ 0.19 |

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| (millions of Canadian dollars, unaudited) | Three Months Ended Mar 31 2014 | Mar 31 2013 |
|---|---|---|
| **Net earnings** | **$ 622** | $ 213 |
| **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 $nil (2013 – $2 million) | **1** | 16 |
| Reclassification to net earnings, net of taxes of $nil (2013 – $nil) | **3** | (1) |
| | **4** | 15 |
| **Foreign currency translation adjustment** | | |
| Translation of net investment | **(2)** | (5) |
| **Other comprehensive income, net of taxes** | **2** | 10 |
| **Comprehensive income** | **$ 624** | $ 223 |

## CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

| (millions of Canadian dollars, unaudited) | Note | Three Months Ended Mar 31 2014 | Mar 31 2013 |
|---|---|---|---|
| **Share capital** | 9 | | |
| Balance – beginning of period | | **$ 3,854** | $ 3,709 |
| Issued upon exercise of stock options | | **195** | 30 |
| Previously recognized liability on stock options exercised for common shares | | **57** | 7 |
| Purchase of common shares under Normal Course Issuer Bid | | **(6)** | (4) |
| Balance – end of period | | **4,100** | 3,742 |
| **Retained earnings** | | | |
| Balance – beginning of period | | **21,876** | 20,516 |
| Net earnings | | **622** | 213 |
| Purchase of common shares under Normal Course Issuer Bid | 9 | **(59)** | (28) |
| Dividends on common shares | 9 | **(246)** | (137) |
| Balance – end of period | | **22,193** | 20,564 |
| **Accumulated other comprehensive income** | 10 | | |
| Balance – beginning of period | | **42** | 58 |
| Other comprehensive income, net of taxes | | **2** | 10 |
| Balance – end of period | | **44** | 68 |
| **Shareholders' equity** | | **$ 26,337** | $ 24,374 |

## CONSOLIDATED STATEMENTS OF CASH FLOWS

| (millions of Canadian dollars, unaudited) | Three Months Ended Mar 31 2014 | Three Months Ended Mar 31 2013 |
|---|---|---|
| **Operating activities** | | |
| Net earnings | **$ 622** | $ 213 |
| Non-cash items | | |
| Depletion, depreciation and amortization | **1,011** | 1,142 |
| Share-based compensation | **143** | 71 |
| Asset retirement obligation accretion | **45** | 42 |
| Unrealized risk management loss | **49** | 62 |
| Unrealized foreign exchange loss | **118** | 78 |
| Realized foreign exchange gain on repayment of US dollar debt securities | **–** | (12) |
| Equity loss from joint venture | **1** | 2 |
| Deferred income tax expense (recovery) | **157** | (27) |
| Other | **31** | 38 |
| Abandonment expenditures | **(87)** | (55) |
| Net change in non-cash working capital | **(737)** | (389) |
| | **1,353** | 1,165 |
| **Financing activities** | | |
| (Repayment) issue of bank credit facilities and commercial paper, net | **(661)** | 1,256 |
| Repayment of medium-term notes | **–** | (400) |
| Issue (repayment) of US dollar debt securities, net | **1,100** | (398) |
| Issue of common shares on exercise of stock options | **195** | 30 |
| Purchase of common shares under Normal Course Issuer Bid | **(65)** | (32) |
| Dividends on common shares | **(217)** | (115) |
| Net change in non-cash working capital | **(5)** | (6) |
| | **347** | 335 |
| **Investing activities** | | |
| Net expenditures on exploration and evaluation assets | **(117)** | (77) |
| Net expenditures on property, plant and equipment | **(1,689)** | (1,604) |
| Net change in non-cash working capital | **109** | 162 |
| | **(1,697)** | (1,519) |
| **Increase (decrease) in cash and cash equivalents** | **3** | (19) |
| **Cash and cash equivalents – beginning of period** | **16** | 37 |
| **Cash and cash equivalents – end of period** | **$ 19** | $ 18 |
| **Interest paid** | **$ 135** | $ 142 |
| **Income taxes paid** | **$ 455** | $ 213 |

## 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 Partnership"), a general partnership formed in the Province of Alberta.

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, 2013, 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, 2013.

## 2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2014, the Company adopted IFRS 9 "Financial Instruments". IFRS 9 replaces the sections of IAS 39 "Financial Instruments: Recognition and Measurement" that relate to the classification and measurement of financial instruments and hedge accounting.

IFRS 9 replaces the multiple classification and measurement models for financial assets with a new model that has only two measurement categories: amortized cost and fair value through profit or loss. This determination is made at initial recognition. For financial liabilities, the new standard retains most of the IAS 39 requirements. The main change arises in cases where the Company chooses to designate a financial liability as fair value through profit or loss. In these situations, the portion of the fair value change related to the Company's own credit risk is recognized in other comprehensive income rather than net earnings. As a result of adopting IFRS 9, all of the Company's financial assets as at December 31, 2013 have been reclassified from loans and receivables at amortized cost to financial assets at amortized cost. There were no changes to the classifications of the Company's financial liabilities. In addition, there were no changes in the carrying values of the Company's financial instruments as a result of the adoption of IFRS 9. The classification and measurement guidance was adopted retrospectively in accordance with the transition provisions of IFRS 9.

The Company also adopted the new hedge accounting guidance in IFRS 9. The new hedge accounting guidance replaces strict quantitative tests of effectiveness with less restrictive assessments of how well the hedging instrument accomplishes the Company's risk management objectives for financial and non-financial risk exposures. IFRS 9 also allows the Company to hedge risk components of non-financial items which meet certain measurability or identifiable characteristics.

Upon adoption of IFRS 9, all of the Company's existing hedging relationships that qualified for hedge accounting under IAS 39 were reassessed with respect to the new hedge accounting requirements in IFRS 9. The hedging relationships have been continued under IFRS 9. The hedge accounting requirements in IFRS 9 have been applied prospectively in accordance with the transition provisions of IFRS 9.

After adoption of IFRS 9, the Company's accounting policies are substantially the same as at December 31, 2013, except for the change in financial asset categories as discussed above.

### 3. EXPLORATION AND EVALUATION ASSETS

| | Exploration and Production | | | Oil Sands Mining and Upgrading | Total |
|---|---|---|---|---|---|
| | North America | North Sea | Offshore Africa | | |
| **Cost** | | | | | |
| At December 31, 2013 | $ 2,570 | $ – | $ 39 | $ – | $ 2,609 |
| Additions | **100** | **–** | **17** | **–** | **117** |
| Transfers to property, plant and equipment | **(47)** | **–** | **–** | **–** | **(47)** |
| Foreign exchange adjustments | **–** | **–** | **1** | **–** | **1** |
| **At March 31, 2014** | **$ 2,623** | **$ –** | **$ 57** | **$ –** | **$ 2,680** |

### 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, 2013 | $ 53,810 | $ 5,200 | $ 3,356 | $ 19,366 | $ 508 | $ 308 | $ 82,548 |
| Additions | **998** | **88** | **–** | **579** | **25** | **10** | **1,700** |
| Transfers from E&E assets | **47** | **–** | **–** | **–** | **–** | **–** | **47** |
| Disposals/derecognitions | **(76)** | **–** | **–** | **(7)** | **–** | **(1)** | **(84)** |
| Foreign exchange adjustments and other | **–** | **205** | **131** | **–** | **–** | **–** | **336** |
| **At March 31, 2014** | **$ 54,779** | **$ 5,493** | **$ 3,487** | **$ 19,938** | **$ 533** | **$ 317** | **$ 84,547** |
| **Accumulated depletion and depreciation** | | | | | | | |
| At December 31, 2013 | $ 28,315 | $ 3,467 | $ 2,551 | $ 1,414 | $ 111 | $ 203 | $ 36,061 |
| Expense | **811** | **57** | **5** | **130** | **2** | **6** | **1,011** |
| Disposals/derecognitions | **(76)** | **–** | **–** | **(7)** | **–** | **(1)** | **(84)** |
| Foreign exchange adjustments and other | **5** | **135** | **118** | **2** | **–** | **–** | **260** |
| **At March 31, 2014** | **$ 29,055** | **$ 3,659** | **$ 2,674** | **$ 1,539** | **$ 113** | **$ 208** | **$ 37,248** |
| **Net book value** | | | | | | | |
| **– at March 31, 2014** | **$ 25,724** | **$ 1,834** | **$ 813** | **$ 18,399** | **$ 420** | **$ 109** | **$ 47,299** |
| – at December 31, 2013 | $ 25,495 | $ 1,733 | $ 805 | $ 17,952 | $ 397 | $ 105 | $ 46,487 |

| **Project costs not subject to depletion and depreciation** | **Mar 31 2014** | Dec 31 2013 |
|---|---|---|
| Horizon | **$ 4,568** | $ 4,051 |
| Kirby Thermal Oil Sands | **$ 389** | $ 1,532 |

During the first quarter of 2014, the Company entered into an agreement to acquire certain producing Canadian crude oil and natural gas properties, together with undeveloped land. In connection with the agreement, the Company arranged an additional $1,000 million unsecured non-revolving bank credit facility maturing March 2016 and with terms similar to the Company's current syndicated credit facilities, available upon closing. Subsequently, the Company completed the acquisition of these properties on April 1, 2014, for preliminary cash consideration of approximately $3,092 million, subject to final closing adjustments.

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 the asset is substantially available for its intended use. For the period ended March 31, 2014, pre-tax interest of $47 million (March 31, 2013 – $36 million) was capitalized to property, plant and equipment using a capitalization rate of 4.3% (March 31, 2013 – 4.5%).

## 5. OTHER LONG-TERM ASSETS

| | **Mar 31 2014** | Dec 31 2013 |
|---|---|---|
| Investment in North West Redwater Partnership | **$ 305** | $ 306 |
| Other | **105** | 136 |
| | **$ 410** | $ 442 |

Other long-term assets include an investment in the 50% owned Redwater Partnership. Based on Redwater Partnership's voting and decision-making structure and legal form, the investment is accounted for as a joint venture using the equity method. Redwater Partnership has entered into agreements 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 ("APMC"), 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 Partnership and its partners.

As at March 31, 2014, Redwater Partnership had interim borrowings of $955 million under credit facilities totaling $1,200 million maturing on November 28, 2014. These facilities are secured by a floating charge on the assets of Redwater Partnership with a mandatory repayment required from future financing proceeds. At maturity or at such later date as mutually agreed to by the lenders and Redwater Partnership, the Company will be obligated to repay its 25% pro rata share of any amount outstanding under the facility. As at May 7, 2014, interim borrowings under the facilities were $883 million.

In April 2014, Redwater Partnership, the Company and APMC amended certain terms of the processing agreements. In conjunction with these amendments, the Company, along with APMC, each committed to provide additional funding up to $350 million to attain Project completion based on the revised Project cost estimate of approximately $8,500 million. The additional funding is to be in the form of subordinated debt bearing interest at prime plus 6%, which is anticipated to form part of the equity toll. As at May 7, 2014, the Company and APMC had each provided $113 million of funding of subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

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

## 6. LONG-TERM DEBT

| | Mar 31 2014 | Dec 31 2013 |
|---|---|---|
| **Canadian dollar denominated debt, unsecured** | | |
| Bank credit facilities | $ 562 | $ 1,246 |
| Medium-term notes | 1,400 | 1,400 |
| | 1,962 | 2,646 |
| **US dollar denominated debt, unsecured** | | |
| Commercial paper (March 31, 2014 – US$500 million; December 31, 2013 – US$500 million) | 553 | 532 |
| US dollar debt securities (March 31, 2014 – US$7,150 million; December 31, 2013 – US$6,150 million) | 7,903 | 6,541 |
| Less: original issue discount on US dollar debt securities (1) | (18) | (18) |
| | 8,438 | 7,055 |
| Fair value impact of interest rate swaps on US dollar debt securities (2) | 6 | 9 |
| | 8,444 | 7,064 |
| Long-term debt before transaction costs | 10,406 | 9,710 |
| Less: transaction costs (1) (3) | (52) | (49) |
| | 10,354 | 9,661 |
| Less: current portion of commercial paper | 553 | 532 |
| current portion of other long-term debt (1) (2) (3) | 945 | 912 |
| | $ 8,856 | $ 8,217 |

*(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% notes due December 2014 was adjusted by $6 million (December 31, 2013 – $9 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, 2014, the Company had in place bank credit facilities of $5,803 million, comprised of:

- a $200 million demand credit facility;
- a $75 million demand credit facility;
- a $1,000 million non-revolving term credit facility maturing March 2016;
- a $1,500 million revolving syndicated credit facility maturing June 2016;
- a $3,000 million revolving syndicated credit facility maturing June 2017; and
- a £15 million demand credit facility related to the Company's North Sea operations.

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

The Company's borrowings under the US commercial paper program are authorized up to a maximum US$1,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

As described in note 4, in connection with the agreement to acquire certain producing Canadian crude oil and natural gas properties, the Company arranged an additional $1,000 million unsecured non-revolving bank credit facility maturing March 2016 and with terms similar to the Company's current syndicated credit facilities, available upon closing. As at May 7, 2014, the Company had $1,000 million outstanding under this facility.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at March 31, 2014 was 1.6% (March 31, 2013 – 2.2%), and on long-term debt outstanding for the period ended March 31, 2014 was 4.3% (March 31, 2013 – 4.5%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $439 million, including a $59 million financial guarantee related to Horizon and $237 million of letters of credit related to North Sea operations, were outstanding at March 31, 2014. Subsequent to March 31, 2014, the financial guarantee related to Horizon was reduced to $56 million.

**Medium-Term Notes**

The Company filed a base shelf prospectus in November 2013 that allows for the issue of up to $3,000 million of medium-term notes in Canada, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

**US Dollar Debt Securities**

During the first quarter of 2014, the Company issued US$500 million of three-month LIBOR plus 0.375% notes due March 2016, and concurrently entered into cross currency swaps to fix the foreign currency exchange rate risk at three-month CDOR plus 0.309% and $555 million (note 13). In addition, the Company issued US$500 million of 3.80% notes due April 2024. Proceeds from the securities were used to repay bank indebtedness. After issuing these securities, the Company has US$2,000 million remaining on its outstanding US$3,000 million base shelf prospectus that allows for the issue of US dollar debt securities in the United States, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

## 7. OTHER LONG-TERM LIABILITIES

| | Mar 31 2014 | Dec 31 2013 |
|---|---|---|
| Asset retirement obligations | $ 4,183 | $ 4,162 |
| Share-based compensation | 368 | 260 |
| Risk management (note 13) | 83 | 136 |
| Other | 60 | 65 |
| | 4,694 | 4,623 |
| Less: current portion | 387 | 275 |
| | $ 4,307 | $ 4,348 |

**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 5.0% (December 31, 2013 – 5.0%). A reconciliation of the discounted asset retirement obligations was as follows:

| | Mar 31 2014 | Dec 31 2013 |
|---|---|---|
| Balance – beginning of period | $ 4,162 | $ 4,266 |
| Liabilities incurred | 11 | 62 |
| Liabilities acquired | – | 131 |
| Liabilities settled | (87) | (207) |
| Asset retirement obligation accretion | 45 | 171 |
| Revision of estimates | – | 375 |
| Change in discount rate | – | (723) |
| Foreign exchange adjustments | 52 | 87 |
| Balance – end of period | $ 4,183 | $ 4,162 |

### 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 2014** | Dec 31 2013 |
|---|---|---|
| Balance – beginning of period | **$ 260** | $ 154 |
| Share-based compensation expense | **143** | 135 |
| Cash payment for stock options surrendered | **(4)** | (4) |
| Transferred to common shares | **(57)** | (50) |
| Capitalized to Oil Sands Mining and Upgrading | **26** | 25 |
| Balance – end of period | **368** | 260 |
| Less: current portion | **284** | 216 |
| | **$ 84** | $ 44 |

## 8. INCOME TAXES

The provision for income tax was as follows:

| | Three Months Ended | |
|---|---|---|
| | **Mar 31 2014** | Mar 31 2013 |
| Current corporate income tax – North America | **$ 192** | $ 122 |
| Current corporate income tax – North Sea | **(15)** | (7) |
| Current corporate income tax – Offshore Africa | **4** | 35 |
| Current PRT [1] recovery – North Sea | **(61)** | (13) |
| Other taxes | **6** | 4 |
| Current income tax expense | **126** | 141 |
| Deferred corporate income tax expense (recovery) | **91** | (4) |
| Deferred PRT [1] expense (recovery) – North Sea | **66** | (23) |
| Deferred income tax expense (recovery) | **157** | (27) |
| Income tax expense | **$ 283** | $ 114 |

*(1) Petroleum Revenue Tax.*

## 9. SHARE CAPITAL

### Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

| Issued common shares | Three Months Ended Mar 31, 2014<br>**Number of shares** (thousands) | | **Amount** |
|---|---|---|---|
| Balance – beginning of period | **1,087,322** | **$** | **3,854** |
| Issued upon exercise of stock options | **6,573** | | **195** |
| Previously recognized liability on stock options exercised for common shares | **–** | | **57** |
| Purchase of common shares under Normal Course Issuer Bid | **(1,775)** | | **(6)** |
| Balance – end of period | **1,092,120** | **$** | **4,100** |

### 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 5, 2014, the Board of Directors approved the regular quarterly dividend at $0.225 per common share, an increase from the previous quarterly dividend of $0.20 per common share, which was approved on November 5, 2013.

### Normal Course Issuer Bid

In April 2014, 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 2014 and ending April 2015, up to 54,596,899 common shares. The Company's Normal Course Issuer Bid announced in 2013 expired April 2014**.**

For the three months ended March 31, 2014, the Company purchased for cancellation 1,775,000 common shares at a weighted average price of $36.83 per common share, for a total cost of $65 million. Retained earnings were reduced by $59 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2014, the Company purchased 330,000 common shares at a weighted average price of $43.44 per common share for a total cost of $14 million.

### Stock Options

The following table summarizes information relating to stock options outstanding at March 31, 2014:

| | Three Months Ended Mar 31, 2014<br>**Stock options** (thousands) | | **Weighted average exercise price** |
|---|---|---|---|
| Outstanding – beginning of period | **72,741** | **$** | **34.36** |
| Granted | **3,723** | **$** | **36.29** |
| Surrendered for cash settlement | **(437)** | **$** | **29.74** |
| Exercised for common shares | **(6,573)** | **$** | **29.64** |
| Forfeited | **(1,150)** | **$** | **35.52** |
| Outstanding – end of period | **68,304** | **$** | **34.93** |
| Exercisable – end of period | **20,276** | **$** | **37.23** |

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 2014** | Mar 31 2013 |
|---|---|---|
| Derivative financial instruments designated as cash flow hedges | **$ 85** | $ 101 |
| Foreign currency translation adjustment | **(41)** | (33) |
| | **$ 44** | $ 68 |

## 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, 2014, 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 2014** | Dec 31 2013 |
|---|---|---|
| Long-term debt (1) | **$ 10,354** | $ 9,661 |
| Total shareholders' equity | **$ 26,337** | $ 25,772 |
| Debt to book capitalization | **28%** | 27% |

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

## 12. NET EARNINGS PER COMMON SHARE

| | Three Months Ended | |
|---|---|---|
| | **Mar 31 2014** | Mar 31 2013 |
| Weighted average common shares outstanding – basic (thousands of shares) | **1,089,929** | 1,092,431 |
| Effect of dilutive stock options (thousands of shares) | **3,298** | 2,057 |
| Weighted average common shares outstanding – diluted (thousands of shares) | **1,093,227** | 1,094,488 |
| Net earnings | **$ 622** | $ 213 |
| Net earnings per common share – basic | **$ 0.57** | $ 0.19 |
| – diluted | **$ 0.57** | $ 0.19 |

## 13. FINANCIAL INSTRUMENTS

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

| | Mar 31, 2014 | | | | |
|---|---|---|---|---|---|
| **Asset (liability)** | **Financial assets at amortized cost** | **Fair value through profit or loss** | **Derivatives used for hedging** | **Financial liabilities at amortized cost** | **Total** |
| Accounts receivable | **$ 1,918** | **$ –** | **$ –** | **$ –** | **$ 1,918** |
| Accounts payable | **–** | **–** | **–** | **(822)** | **(822)** |
| Accrued liabilities | **–** | **–** | **–** | **(2,653)** | **(2,653)** |
| Other long-term liabilities | **–** | **(88)** | **5** | **(51)** | **(134)** |
| Long-term debt [(1)] | **–** | **–** | **–** | **(10,354)** | **(10,354)** |
| | **$ 1,918** | **$ (88)** | **$ 5** | **$ (13,880)** | **$ (12,045)** |

| | Dec 31, 2013 | | | | |
|---|---|---|---|---|---|
| Asset (liability) | Financial assets at amortized cost | Fair value through profit or loss | Derivatives used for hedging | Financial liabilities at amortized cost | Total |
| Accounts receivable | $ 1,427 | $ – | $ – | $ – | $ 1,427 |
| Accounts payable | – | – | – | (637) | (637) |
| Accrued liabilities | – | – | – | (2,519) | (2,519) |
| Other long-term liabilities | – | (39) | (97) | (56) | (192) |
| Long-term debt [(1)] | – | – | – | (9,661) | (9,661) |
| | $ 1,427 | $ (39) | $ (97) | $ (12,873) | $ (11,582) |

*(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 recurring other long-term liabilities and fixed rate long-term debt were outlined below:

| | Mar 31, 2014 | | |
|---|---|---|---|
| | **Carrying amount** | **Fair value** | |
| **Asset (liability)** [(1) (5)] | | **Level 1** | **Level 2** |
| Other long-term liabilities | **$ (83)** | **$ –** | **$ (83)** |
| Fixed rate long-term debt [(2) (3) (4)] | **(9,239)** | **(10,305)** | **–** |
| | **$ (9,322)** | **$ (10,305)** | **$ (83)** |

| | Dec 31, 2013 | | |
|---|---|---|---|
| | Carrying amount | Fair value | |
| Asset (liability) [(1) (5)] | | Level 1 | Level 2 |
| Other long-term liabilities | $ (136) | $ – | $ (136) |
| Fixed rate long-term debt [(2) (3) (4)] | (7,883) | (8,628) | – |
| | $ (8,019) | $ (8,628) | $ (136) |

*(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% notes due December 2014 was adjusted by $6 million (December 31, 2013 – $9 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.*

*(5) There were no transfers between Level 1 and Level 2 financial instruments.*

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

| Asset (liability) | | Mar 31, 2014 | | Dec 31, 2013 |
|---|---|---|---|---|
| **Derivatives held for trading** | | | | |
| Crude oil price collars | **$** | **(30)** | $ | (33) |
| Foreign currency forward contracts | | **(10)** | | (3) |
| Natural gas AECO basis swaps | | **(34)** | | (1) |
| Natural gas AECO put options, net of put premium financing obligations | | **(14)** | | (2) |
| Natural gas price collars | | **–** | | – |
| **Cash flow hedges** | | | | |
| Foreign currency forward contracts | | **(2)** | | (1) |
| Cross currency swaps | | **7** | | (96) |
| | **$** | **(83)** | $ | (136) |
| Included within: | | | | |
| Current portion of other long-term liabilities | **$** | **(82)** | $ | (38) |
| Other long-term liabilities | | **(1)** | | (98) |
| | **$** | **(83)** | $ | (136) |

For the period ended March 31, 2014, the Company recognized a gain of $nil (December 31, 2013 – gain of $4 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 1 and Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 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 quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. 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.

**Risk Management**

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

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

| Asset (liability) | | Three Months Ended Mar 31, 2014 | | Year Ended Dec 31, 2013 |
|---|---|---|---|---|
| Balance – beginning of period | **$** | **(136)** | $ | (257) |
| Cost of outstanding put options | | **15** | | 9 |
| Net change in fair value of outstanding derivative financial instruments recognized in: | | | | |
| Risk management activities | | **(49)** | | (39) |
| Foreign exchange | | **98** | | 165 |
| Other comprehensive income | | **4** | | (5) |
| | | **(68)** | | (127) |
| Add: put premium financing obligations [(1)] | | **(15)** | | (9) |
| Balance – end of period | | **(83)** | | (136) |
| Less: current portion | | **(82)** | | (38) |
| | **$** | **(1)** | $ | (98) |

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

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

| | Three Months Ended | |
|---|---|---|
| | **Mar 31 2014** | Mar 31 2013 |
| Net realized risk management gain | **$ (75)** | $ (83) |
| Net unrealized risk management loss | **49** | 62 |
| | **$ (26)** | $ (21) |

**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, 2014, 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 (1) | Apr 2014 – Jun 2014 | 50,000 bbl/d | US$80.00 – US$123.09 | Brent |
| | Apr 2014 – Dec 2014 | 50,000 bbl/d | US$75.00 – US$121.57 | Brent |
| | Apr 2014 – Dec 2014 | 50,000 bbl/d | US$80.00 – US$120.17 | Brent |
| | Apr 2014 – Dec 2014 | 50,000 bbl/d | US$90.00 – US$120.10 | Brent |
| | Jul 2014 – Sep 2014 | 50,000 bbl/d | US$80.00 – US$122.09 | Brent |
| | Jan 2015 – Dec 2015 | 8,000 bbl/d | US$80.00 – US$122.53 | Brent |
| | Apr 2014 – Jun 2014 | 50,000 bbl/d | US$80.00 – US$107.84 | WTI |
| | Apr 2014 – Dec 2014 | 50,000 bbl/d | US$75.00 – US$105.54 | WTI |
| | Jul 2014 – Dec 2014 | 50,000 bbl/d | US$80.00 – US$107.81 | WTI |

*(1) Subsequent to March 31, 2014, the Company entered into an additional 42,000 bbl/d of US$80.00 – US$120.33 Brent collars for the period January to December 2015.*

| | Remaining term | Volume | Weighted average price | Index |
|---|---|---|---|---|
| **Natural gas** | | | | |
| AECO basis swaps | Apr 2014 – Oct 2014 | 500,000 MMBtu/d | US$0.50 | AECO/NYMEX |
| Put options | Apr 2014 – Oct 2014 | 750,000 GJ/d | $3.10 | AECO |
| Price collars | Apr 2014 – Dec 2014 | 200,000 GJ/d | $4.00 – $5.03 | AECO |

The cost of outstanding put options and their respective periods of settlement as at March 31, 2014 were as follows:

| | Q2 2014 | Q3 2014 | Q4 2014 |
|---|---|---|---|
| Cost | $6 | $7 | $2 |

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. 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, 2014, 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 and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, 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, 2014, 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 2014 | – | Mar 2016 | US$500 | 1.109 | Three-month LIBOR plus 0.375% | Three-month CDOR [(1)] plus 0.309% |
| | Apr 2014 | – | Aug 2016 | US$250 | 1.116 | 6.00% | 5.40% |
| | Apr 2014 | – | May 2017 | US$1,100 | 1.170 | 5.70% | 5.10% |
| | Apr 2014 | – | Nov 2021 | US$500 | 1.022 | 3.45% | 3.96% |
| | Apr 2014 | – | Mar 2038 | US$550 | 1.170 | 6.25% | 5.76% |

*(1) Canadian Dealer Offered Rate ("CDOR").*

All cross currency swap derivative financial instruments designated as hedges at March 31, 2014, were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at March 31, 2014, the Company had US$2,193 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$500 million designated 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, 2014, 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, 2014, the Company had net risk management assets of $3 million with specific counterparties related to derivative financial instruments (December 31, 2013 – $nil).

### c) Liquidity risk

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

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, 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 were as follows:

| | Less than 1 year | 1 to less than 2 years | 2 to less than 5 years | Thereafter |
|---|---|---|---|---|
| Accounts payable | $ 822 | $ – | $ – | $ – |
| Accrued liabilities | $ 2,653 | $ – | $ – | $ – |
| Risk management | $ 82 | $ 9 | $ 6 | $ (14) |
| Other long-term liabilities | $ 21 | $ 30 | $ – | $ – |
| Long-term debt (1) | $ 1,493 | $ 952 | $ 2,497 | $ 5,476 |

*(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 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter |
|---|---|---|---|---|---|---|
| Product transportation and pipeline | $ 238 | $ 307 | $ 238 | $ 212 | $ 176 | $ 1,324 |
| Offshore equipment operating leases and offshore drilling | $ 119 | $ 247 | $ 84 | $ 63 | $ 57 | $ 18 |
| Office leases | $ 29 | $ 44 | $ 45 | $ 48 | $ 50 | $ 343 |
| Other | $ 239 | $ 173 | $ 72 | $ 1 | $ 1 | $ 1 |

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 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, 2014 | North America 2013 | North Sea, Three Months Ended Mar 31, 2014 | North Sea 2013 | Offshore Africa, Three Months Ended Mar 31, 2014 | Offshore Africa 2013 | Total Exploration and Production, Three Months Ended Mar 31, 2014 | Total Exploration and Production 2013 |
|---|---|---|---|---|---|---|---|---|
| **Segmented product sales** | **3,657** | 2,808 | **198** | 177 | **24** | 208 | **3,879** | 3,193 |
| Less: royalties | **(516)** | (276) | **(1)** | (1) | **(4)** | (33) | **(521)** | (310) |
| **Segmented revenue** | **3,141** | 2,532 | **197** | 176 | **20** | 175 | **3,358** | 2,883 |
| **Segmented expenses** | | | | | | | | |
| Production | **663** | 605 | **123** | 102 | **7** | 47 | **793** | 754 |
| Transportation and blending | **828** | 855 | **2** | 2 | **–** | – | **830** | 857 |
| Depletion, depreciation and amortization | **816** | 871 | **58** | 112 | **5** | 40 | **879** | 1,023 |
| Asset retirement obligation accretion | **22** | 23 | **9** | 9 | **2** | 2 | **33** | 34 |
| Realized risk management activities | **(75)** | (83) | **–** | – | **–** | – | **(75)** | (83) |
| Equity loss from joint venture | **–** | – | **–** | – | **–** | – | **–** | – |
| **Total segmented expenses** | **2,254** | 2,271 | **192** | 225 | **14** | 89 | **2,460** | 2,585 |
| **Segmented earnings (loss) before the following** | **887** | 261 | **5** | (49) | **6** | 86 | **898** | 298 |
| **Non–segmented expenses** | | | | | | | | |
| Administration | | | | | | | | |
| Share–based compensation | | | | | | | | |
| Interest and other financing expense | | | | | | | | |
| Unrealized risk management activities | | | | | | | | |
| Foreign exchange loss | | | | | | | | |
| **Total non–segmented expenses** | | | | | | | | |
| **Earnings before taxes** | | | | | | | | |
| Current income tax expense | | | | | | | | |
| Deferred income tax expense (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 | |
|---|---|---|---|---|---|---|---|---|
| | **2014** | 2013 | **2014** | 2013 | **2014** | 2013 | **2014** | 2013 |
| **Segmented product sales** | **1,082** | 909 | **31** | 27 | **(24)** | (28) | **4,968** | 4,101 |
| Less: royalties | **(51)** | (36) | **–** | – | **–** | – | **(572)** | (346) |
| **Segmented revenue** | **1,031** | 873 | **31** | 27 | **(24)** | (28) | **4,396** | 3,755 |
| **Segmented expenses** | | | | | | | | |
| Production | **412** | 377 | **9** | 8 | **(3)** | (4) | **1,211** | 1,135 |
| Transportation and blending | **20** | 15 | **–** | – | **(19)** | (17) | **831** | 855 |
| Depletion, depreciation and amortization | **130** | 117 | **2** | 2 | **–** | – | **1,011** | 1,142 |
| Asset retirement obligation accretion | **12** | 8 | **–** | – | **–** | – | **45** | 42 |
| Realized risk management activities | **–** | – | **–** | – | **–** | – | **(75)** | (83) |
| Equity loss from joint venture | **–** | – | **1** | 2 | **–** | – | **1** | 2 |
| **Total segmented expenses** | **574** | 517 | **12** | 12 | **(22)** | (21) | **3,024** | 3,093 |
| **Segmented earnings (loss) before the following** | **457** | 356 | **19** | 15 | **(2)** | (7) | **1,372** | 662 |
| **Non–segmented expenses** | | | | | | | | |
| Administration | | | | | | | **90** | 79 |
| Share–based compensation | | | | | | | **143** | 71 |
| Interest and other financing expense | | | | | | | **68** | 77 |
| Unrealized risk management activities | | | | | | | **49** | 62 |
| Foreign exchange loss | | | | | | | **117** | 46 |
| **Total non–segmented expenses** | | | | | | | **467** | 335 |
| **Earnings before taxes** | | | | | | | **905** | 327 |
| Current income tax expense | | | | | | | **126** | 141 |
| Deferred income tax expense (recovery) | | | | | | | **157** | (27) |
| **Net earnings** | | | | | | | **622** | 213 |

**Capital Expenditures** [1]

| | Three Months Ended | | | | | |
|---|---|---|---|---|---|---|
| | **Mar 31, 2014** | | | Mar 31, 2013 | | |
| | **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 | **$ 100** | **$ (47)** | **$ 53** | $ 76 | $ (22) | $ 54 |
| North Sea | **–** | **–** | **–** | – | – | – |
| Offshore Africa | **17** | **–** | **17** | 1 | – | 1 |
| | **$ 117** | **$ (47)** | **$ 70** | $ 77 | $ (22) | $ 55 |
| **Property, plant and equipment** | | | | | | |
| Exploration and Production | | | | | | |
| North America | **$ 987** | **$ (18)** | **$ 969** | $ 1,017 | $ (34) | $ 983 |
| North Sea | **88** | **–** | **88** | 85 | – | 85 |
| Offshore Africa | **–** | **–** | **–** | 29 | – | 29 |
| | **1,075** | **(18)** | **1,057** | 1,131 | (34) | 1,097 |
| Oil Sands Mining and Upgrading [3] | **579** | **(7)** | **572** | 461 | (116) | 345 |
| Midstream | **25** | **–** | **25** | 5 | – | 5 |
| Head office | **10** | **(1)** | **9** | 7 | – | 7 |
| | **$ 1,689** | **$ (26)** | **$ 1,663** | $ 1,604 | $ (150) | $ 1,454 |

*(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 2014** | Dec 31 2013 |
| Exploration and Production | | |
| North America | **$ 29,918** | $ 29,234 |
| North Sea | **2,059** | 1,964 |
| Offshore Africa | **1,009** | 981 |
| Other | **50** | 25 |
| Oil Sands Mining and Upgrading | **19,209** | 18,604 |
| Midstream | **894** | 841 |
| Head office | **109** | 105 |
| | **$ 53,248** | $ 51,754 |

## 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 November 2013. 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, 2014:

| | |
|---|---|
| Interest coverage (times) | |
| Net earnings [(1)] | 8.8x |
| Cash flow from operations [(2)] | 20.0x |

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

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

**CONFERENCE CALL**

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Friday, May 9, 2014. The North American conference call number is 1-877-223-4471 and the outside North American conference call number is 001-647-788-4922. Please call in about 10 minutes before the starting time in order to be patched into the call.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Friday, May 16, 2014. To access the rebroadcast in North America, dial 1-800-585-8367. Those outside of North America, dial 001-416-621-4642. The conference ID number to use is 58303226.

**WEBCAST**

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

For further information, please contact:


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