PRESS RELEASE

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CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2013 FOURTH QUARTER AND YEAR END RESULTS

CALGARY, ALBERTA – MARCH 6, 2014 – FOR IMMEDIATE RELEASE

Commenting on fourth quarter and year end results, Steve Laut, President of Canadian Natural stated, "2013 was a solid year for Canadian Natural as we achieved significant progress in our transition to longer life, low decline assets. We achieved record cash flow of approximately $7.5 billion in 2013 and we grew our total liquids production by 6% to approximately 478,000 barrels per day, with total production of 671,162 barrels of oil equivalent per day. Additionally, we increased total Company Gross proved plus probable reserves to 7.99 billion BOE, replacing 143% of production, with a proved plus probable reserve life index of approximately 35 years.

During 2013, Canadian Natural continued to effectively execute our strategy to transform our asset base to longer life, low decline production. The Kirby South SAGD project achieved first steam injection ahead of schedule and on budget during the third quarter of 2013. Production is targeted to ramp up to 40,000 barrels per day of crude oil by the end of 2014. This is an important step in the development of our in situ oil sands reserves. Expansion of Horizon to 250,000 barrels per day is tracking 10% below cost estimates, with Phase 2A targeted to add 12,000 barrels per day of additional SCO production capacity in 2014, ahead of the original 2015 plan. Horizon also achieved a step change in reliability this year as a result of several initiatives including the successful completion of the first major planned turnaround. Horizon averaged over 100,000 barrels per day of high quality synthetic crude oil during 2013, an increase of 17% over the 2012 average volumes and within the original 2013 budgeted guidance.

In 2013 production growth was solid, driving our record cash flow. The facilities at our leading edge Pelican Lake polymer flood were expanded in 2013 and associated crude oil production increased 12% year over year. Canadian Natural had 7% production growth in North American light crude oil and NGLs and 9% production growth in primary heavy crude oil in 2013 over 2012. We maintain an enviable position with our vast and balanced asset base; and we target all aspects of the business to generate free cash flow while maximizing returns to our shareholders."

Canadian Natural's Chief Financial Officer, Corey Bieber, continued, "Our record cash flow of approximately $7.5 billion was due to strong operating performance overall and a healthy price environment, which contributed to a 24% increase in cash flow over the comparable period in 2012. We exited the year with a strong balance sheet, with debt to book capitalization of 27% and debt to EBITDA of 1.1 times.

As a result of the Company's continued strength and successful execution of our proven effective strategy, the Company's Board of Directors, as part of its annual review of dividend payment levels concurrently with the approval of the Company's year-end financial statements, have increased the quarterly dividend to $0.225 per share. This increase is in addition to the aggregate quarterly dividend increase of 90% announced during 2013. In addition, as part of our Normal Course Issuer Bid in 2013, we purchased 10.2 million common shares for cancellation.

Our balance sheet allows us the flexibility to continue to develop the assets with the highest returns while we generate substantial and growing free cash flow which can be allocated to resource development, sustainable dividends, share purchases, opportunistic acquisitions, and debt repayment."

QUARTERLY AND ANNUAL HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended Dec 31 2013	Sep 30 2013	Dec 31 2012	Year Ended Dec 31 2013	Dec 31 2012
Net earnings	**$ 413**	$ 1,168	$ 352	**$ 2,270**	$ 1,892
Per common share – basic	**$ 0.38**	$ 1.07	$ 0.32	**$ 2.08**	$ 1.72
– diluted	**$ 0.38**	$ 1.07	$ 0.32	**$ 2.08**	$ 1.72
Adjusted net earnings from operations (1)	**$ 563**	$ 1,009	$ 359	**$ 2,435**	$ 1,618
Per common share – basic	**$ 0.52**	$ 0.93	$ 0.33	**$ 2.24**	$ 1.48
– diluted	**$ 0.52**	$ 0.93	$ 0.33	**$ 2.23**	$ 1.47
Cash flow from operations (2)	**$ 1,782**	$ 2,454	$ 1,548	**$ 7,477**	$ 6,013
Per common share – basic	**$ 1.64**	$ 2.26	$ 1.41	**$ 6.87**	$ 5.48
– diluted	**$ 1.64**	$ 2.26	$ 1.41	**$ 6.86**	$ 5.47
Capital expenditures, net of dispositions	**$ 2,091**	$ 1,655	$ 1,767	**$ 7,274**	$ 6,308
Daily production, before royalties					
Natural gas (MMcf/d)	**1,195**	1,163	1,134	**1,158**	1,220
Crude oil and NGLs (bbl/d)	**478,038**	509,182	469,964	**478,240**	451,378
Equivalent production (BOE/d) (3)	**677,242**	702,938	658,973	**671,162**	654,665

(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.

Annual

- Total overall production for the year averaged 671,162 BOE/d representing an increase of 3% from 2012. Canadian Natural's production volumes were driven by greater reliability of Horizon Oil Sands ("Horizon") operations, successful light and primary heavy crude oil drilling programs and strong production at Pelican Lake, and offset by planned production declines in natural gas.
- Total crude oil and NGLs production for the year averaged 478,240 bbl/d, an increase of 6% from 2012. Crude oil production increased in 2013 as follows:
  - 17% annual increase in Horizon production,
  - 12% annual increase in Pelican Lake production,
  - 9% annual increase in primary heavy crude oil production, and,
  - 7% annual increase in North America light crude oil and NGLs production.
- Total natural gas production for the year averaged 1,158 MMcf/d and was minimized to a 5% decrease from 2012 due to liquids-rich natural gas development at Septimus and minor acquisitions throughout the year. The decrease reflects expected production declines and Canadian Natural's strategic decision to allocate capital to higher return crude oil projects.
- Canadian Natural realized record cash flow from operations in 2013 of approximately $7.5 billion. This is a 24% increase in cash flow compared to approximately $6.0 billion in 2012. The increase in cash flow was primarily due to higher overall crude oil volumes and higher realized synthetic crude oil ("SCO") and natural gas prices.

- Adjusted net earnings from operations increased to $2.4 billion in 2013 compared to $1.6 billion in 2012. Changes in adjusted net earnings reflect the changes in cash flow from operations partially offset by higher depletion, depreciation and amortization ("DD&A") expense.
- Canadian Natural's crude oil and natural gas reserves were reviewed and evaluated by Independent Qualified Reserves Evaluators. The following highlights are based on the Company's reserves using forecast prices and costs as at December 31, 2013:
  - North America E&P Company Gross proved crude oil, bitumen and NGLs reserves increased 8% to 1.89 billion barrels. Company Gross proved natural gas reserves increased 4% to 4.16 Tcf. Total proved BOE increased 7% to 2.58 billion barrels, with a reserve replacement ratio of 188%.
  - North America E&P Company Gross proved plus probable crude oil, bitumen and NGLs reserves increased 4% to 3.21 billion barrels. Company Gross proved plus probable natural gas reserves increased 6% to 5.88 Tcf. Total proved plus probable BOE increased 4% to 4.19 billion barrels, with a reserve replacement ratio of 191%.
  - Thermal oil sands (bitumen) Company Gross proved reserves increased 9% to 1.16 billion barrels primarily due to category transfers from probable undeveloped to proved undeveloped at Kirby North and new proved undeveloped additions at Primrose and Wolf Lake. Proved reserve additions and revisions were 126 million barrels. Total proved plus probable bitumen reserves increased 2% to 2.17 billion barrels.
  - Canadian Natural total Company Gross proved crude oil, SCO, bitumen and NGLs reserves increased 2% to 4.42 billion barrels. Company Gross proved natural gas reserves increased 4% to 4.31 Tcf. Total proved reserves increased 2% to 5.14 billion BOE, resulting in a reserve life index of 22.8 years.
  - Canadian Natural total Company Gross proved reserves increased by 364 million BOE through additions and revisions, resulting in a proved reserve replacement ratio of 149%.
  - Canadian Natural total Company Gross proved plus probable crude oil, SCO, bitumen and NGLs reserves increased 1% to 6.97 billion barrels. Company Gross proved plus probable natural gas reserves increased 6% to 6.11 Tcf. Total proved plus probable reserves increased 1% to 7.99 billion BOE resulting in a reserve life index of 35.4 years.
  - Canadian Natural total Company Gross proved plus probable reserves increased by 350 million BOE through additions and revisions, resulting in a proved plus probable reserve replacement ratio of 143%.
- Total net exploration and production reserve replacement expenditures totaled approximately $4.24 billion in 2013, including acquisitions and excluding Horizon. Horizon project capital (including capitalized interest, share-based compensation and other) totaled approximately $2.21 billion and sustaining and turnaround capital totaled approximately $378 million.
- Subsequent to Q4/13, the Company announced an agreement to acquire certain Canadian assets of Devon Canada ("Devon Assets") for total cash consideration of approximately $3.125 billion, effective January 1, 2014, with a targeted closing date of April 1, 2014. The Devon Assets are all located in Western Canada in areas adjacent or proximal to Canadian Natural's current operations and are high quality, concentrated liquids-rich natural gas weighted assets, with additional light crude oil exposure. Devon Assets also include associated key strategic facilities, a royalty revenue stream and undeveloped land. The acquired Company Gross proved reserves, excluding the royalty land position, are 272.2 million BOE, as evaluated by an Independent Qualified Reserves Evaluator retained by Devon, as at December 31, 2013 using forecast prices and costs.

Fourth Quarter

- Total crude oil and NGLs production was 478,038 bbl/d for Q4/13. Q4/13 crude oil and NGLs production volumes increased 2% from Q4/12 largely as a result of safe, steady and reliable production at Horizon, production growth at Pelican Lake and increased NGLs production. Q4/13 crude oil and NGLs production volumes decreased 6% from Q3/13 as a result of lower thermal production, as expected, and lower primary heavy crude oil production. This decrease was primarily due to the strategic temporary reduction of primary heavy crude oil production in response to wider WCS heavy differentials and the impact on primary heavy crude oil production volumes at Woodenhouse due to the temporary loss of a third party fuel gas pipeline.
- Total natural gas production was 1,195 MMcf/d in Q4/13, an increase of 5% and 3% from Q4/12 and Q3/13 respectively. The increase in production is largely due to the concentrated liquids-rich Montney natural gas drilling program at Septimus, as well as minor property acquisitions.
- Canadian Natural generated quarterly cash flow from operations of $1.78 billion compared with $1.55 billion in Q4/12 and $2.45 billion in Q3/13. The increase in cash flow from Q4/12 was due to higher SCO sales volumes, higher crude oil and NGLs sales volumes in Offshore Africa, and the impact of a weaker Canadian dollar relative to the US dollar, partially offset by lower North America crude oil and NGLs sales volumes. The decrease in cash flow

from Q3/13 was due to lower realized SCO and North America crude oil and NGLs prices and expected lower crude oil and NGLs sales volumes in North America. These factors were partially offset by higher crude oil and NGLs sales volumes in Offshore Africa.

- Adjusted net earnings from operations for Q4/13 were $563 million, compared to adjusted net earnings of $359 million in Q4/12 and $1,009 million Q3/13. Changes in adjusted net earnings reflect the changes in cash flow from operations.

Operational and Financial

- In 2013 North America light oil and NGLs production volumes increased 7% from 2012.
  - The plant expansion at Septimus, the Company's premium liquids-rich natural gas Montney play, was completed during Q3/13. During the first week of September 2013, the newly expanded gas plant reached its production capacity of 125 MMcf/d and approximately 12,200 bbl/d of liquids with the completion of new wells. With high liquids yields and low operating costs of approximately $0.22/Mcfe, Septimus continues to generate excellent returns and significant free cash flow while maximizing the utilization of the plant capacity.
  - In Q3/13, Canadian Natural completed the acquisition of Barrick Energy Inc. for approximately $173 million. The production and undeveloped land base is complementary to Canadian Natural's existing assets and is concentrated in light oil weighted assets with strong netbacks and a long reserve life. This acquisition added approximately 4,200 bbl/d of light crude oil and NGLs and 4 MMcf/d of natural gas production. These assets have been integrated into the Company's operations and optimization opportunities are underway.
- Canadian Natural's primary heavy crude oil continued to provide strong netbacks and amongst the highest returns on capital in the Company's portfolio of diverse and balanced assets. Primary heavy crude oil operations achieved annual production volumes of approximately 136,000 bbl/d, representing an average annual production growth of 9% over 2012. The Q4/13 primary heavy crude oil production volumes were approximately 135,000 bbl/d, a 3% increase from Q4/12 and a 4% decrease from Q3/13 levels. The decrease in production levels from the previous quarter was largely due to the strategic temporary reduction of production levels by approximately 10,500 bbl/d of primary heavy crude oil production volumes for approximately 30 days in response to wider WCS heavy differentials.
- WCS differentials to WTI widened to 40% in December. To partially mitigate the cash flow impact from temporarily wider differentials, the Company strategically curtailed production levels by approximately 10,500 bbl/d of primary heavy crude oil production volumes for approximately 30 days. Primary heavy crude oil production volumes were deferred to January and February, when differentials narrowed to 31% and 19% respectively.
- Pelican Lake achieved record quarterly crude oil production of approximately 46,000 bbl/d in Q4/13, a 27% increase from Q4/12 and a 1% increase from Q3/13 levels. This is the fourth consecutive quarter of production increases, which reflects Canadian Natural's continued success in implementing polymer flooding technology at this property. Pelican Lake's industry leading operating costs of $9.25/bbl in Q4/13 represent a 28% decrease from Q4/12 levels. The increasing polymer flood production response combined with continued optimization and effective and efficient operations have driven cost improvements, resulting in increasing free cash flow generation.
- Kirby South, a 100% owned and operated SAGD project, was completed during Q3/13, on budget, at a cost of approximately $30,000 per flowing barrel. At the end of Q4/13, steam was being circulated in 36 well pairs on 6 pads to initiate the SAGD process. Subsequent to Q4/13, 15 well pairs have been converted to SAGD production as planned. The wells at Kirby South are responding as expected and production is targeted to grow to 40,000 bbl/d in Q4/14. All evaporators, steam generators and oil treating vessels are in service and the first shipment of crude oil produced was delivered during Q4/13 with production averaging 1,500 bbl/d for the quarter. Production ramp up continues as expected, with current production of approximately 7,000 bbl/d.
- Horizon achieved strong and reliable operating performance for all of 2013. Horizon SCO production averaged approximately 112,000 bbl/d in the second half of 2013 upon the completion of the first major turnaround. The Q4/13 production volumes of 112,273 bbl/d represent a 35% increase from Q4/12 levels, indicating a step change in safe, steady and reliable production at Horizon. Canadian Natural expects continued strong operating performance, and for the first two months of 2014 production has averaged approximately 111,000 bbl/d. Horizon production is targeted to increase by 11% in 2014 from 2013 levels as a result of the continued focus on effective and efficient operations.

- During 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for a net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in an after-tax gain on sale of exploration and evaluation property of $166 million. In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery. Long lead equipment has been ordered and the operator is targeting to drill the first exploration well in Q3/14.
- For the year ended December 31, 2013, Canadian Natural purchased for cancellation under its Normal Course Issuer Bid 10,164,800 common shares at a weighted average price of $31.46 per common share. Subsequent to December 31, 2013, to date in 2014 the Company has purchased for cancellation 1,475,000 common shares at a weighted average price of $35.85 per common share.
- As a result of the Company's continued strength and successful execution of its proven and effective strategy, Canadian Natural's Board of Directors has increased the quarterly cash dividend on common shares to C$0.225 per share payable on April 1, 2014. This increase is in addition to the aggregate quarterly dividend increase of 90% announced during 2013 and represents a 13% increase over the previous quarterly dividend. This is the fourteenth consecutive year of dividend increases since the Company first paid a dividend in 2001, and a compound annual growth rate of 34% from 2009 when Horizon first commenced production. This dividend reflects the continued strong operational results of the Company and the successful execution to date on the thermal development program and Horizon Phase 2/3 development, both in terms of construction accomplished and cost performance to date and the amount of future contracts that have been awarded.

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 its production facilities, 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

Activity by core region

	Net unproved property as at Dec 31, 2013 (thousands of net acres)[1]	Drilling activity year ended Dec 31, 2013 (net wells)[2]
North America		
Northeast British Columbia	**2,956**	**31.4**
Northwest Alberta	**2,454**	**60.3**
Northern Plains	**7,131**	**913.3**
Southern Plains	**1,128**	**31.0**
Southeast Saskatchewan	**106**	**23.5**
Thermal In Situ Oil Sands	**838**	**280.0**
	14,613	**1,339.5**
Oil Sands Mining and Upgrading	**59**	**234.0**
North Sea	**110**	**1.0**
Offshore Africa	**2,467**	**0.0**
	17,249	**1,574.5**

(1) Unproved property refers to a property or part of a property to which no reserves have been specifically attributed.
(2) Drilling activity includes stratigraphic test and service wells.

Drilling activity (number of wells)

	Year Ended Dec 31			
	2013		2012	
	Gross	**Net**	Gross	Net
Crude oil	**1,180**	**1,117**	1,255	1,203
Natural gas	**60**	**44**	42	35
Dry	**31**	**30**	34	33
Subtotal	**1,271**	**1,191**	1,331	1,271
Stratigraphic test / service wells	**384**	**384**	728	727
Total	**1,655**	**1,575**	2,059	1,998
Success rate (excluding stratigraphic test / service wells)		**97%**		97%

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Crude oil and NGLs production (bbl/d)	**254,162**	256,329	230,621	**247,196**	227,351
Net wells targeting crude oil	**299**	294	275	**1,000**	1,075
Net successful wells drilled	**289**	287	256	**974**	1,042
Success rate	**97%**	98%	93%	**97%**	97%

- North America crude oil and NGLs production averaged 247,196 bbl/d for the year, an increase of 9% from 2012 levels. The increase was largely driven by successful light and primary heavy crude oil drilling programs, strong performance at Pelican Lake and acquisitions.
- North America crude oil and NGLs production for Q4/13 was 254,162 bbl/d. Q4/13 crude oil and NGLs production volumes increased 10% from Q4/12 as a result of strong performance in light oil, NGLs, Pelican Lake and primary heavy crude oil production. Crude oil and NGLs production volumes decreased 1% from Q3/13 levels, as a result of the strategic temporary reduction of approximately 10,500 bbl/d of primary heavy crude oil production volumes for approximately 30 days in response to wider WCS heavy differentials.
- Woodenhouse returned to full production rates upon the restoration of third party fuel gas supply on November 21, 2013, with December primary heavy crude oil production volumes approaching 16,000 bbl/d. Fuel gas supply to the Woodenhouse operation was interrupted for a period of time as a result of a third party fuel pipeline issue which resulted in a reduction of production volumes by approximately 1,200 bbl/d, on average, during Q4/13, as the Company had to acquire an alternative fuel source to substantially mitigate the disruption.
- Canadian Natural drilled 259 net primary heavy crude oil wells in Q4/13, completing an effective and efficient annual drilling program of 859 net primary heavy crude oil wells during 2013. The Company will continue the drilling program in 2014, leveraging drilling efficiencies, with the target to drill 898 net primary heavy crude oil wells. Canadian Natural's primary heavy crude oil continues to provide strong netbacks and a high return on capital in the Company's portfolio of diverse and balanced assets.
- Pelican Lake achieved record quarterly heavy crude oil production of approximately 46,000 bbl/d in Q4/13, a 27% increase from Q4/12 and a 1% increase from Q3/13 levels. This is the fourth consecutive quarter of production increases, which reflects Canadian Natural's continued success in implementing polymer flooding technology at this property. Twelve net horizontal production wells were drilled during the quarter and 17 net horizontal production wells are targeted to be drilled in 2014. Pelican Lake's industry leading operating costs of $9.25/bbl in Q4/13 represent a 28% decrease in operating costs from Q4/12. The increasing polymer flood production response combined with continued optimization and effective and efficient operations have driven cost improvements, resulting in increasing free cash flow generation.

- North America light crude oil and NGLs achieved record quarterly production of approximately 73,400 bbl/d in Q4/13. Production increased 4% from Q3/13, partially as a result of increased NGLs production associated with the Septimus project expansion and minor property acquisitions. The Company drilled 28 net light crude oil wells in Q4/13. 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			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Bitumen production (bbl/d)	**78,069**	109,200	121,362	**96,503**	99,478
Net wells targeting bitumen	**38**	47	38	**145**	161
Net successful wells drilled	**35**	47	38	**142**	161
Success rate	**92%**	100%	100%	**98%**	100%

- Average annual thermal in situ production for 2013 was approximately 97,000 bbl/d representing a decrease of 3% from 2012. Q4/13 thermal in situ production volumes were approximately 78,000 bbl/d due to the timing of steaming and production cycles and steaming restrictions.
- 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. Canadian Natural continues to work with Alberta Environment and Sustainable Resource Development ("AESRD") on an effective and efficient clean-up. Cleanup of the 3 Primrose East sites is complete and the Primrose South site cleanup is targeted to be completed in Q1/14.
- The causation review of the bitumen emulsion seepage is progressing well. The significant amount of data collected to date indicates the cause of the bitumen emulsion seepage is the mechanical failures of wellbores. No data collected to date supports any other potential failure mechanisms. The method to prevent seepages for all potential failure mechanisms has been developed and includes the remediation of legacy wellbores, modified steaming strategies, enhanced monitoring techniques and proactive response strategies.
- Canadian Natural continues to work 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 reduced in certain areas until the causation review with the AER is complete. 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.
- Kirby South, a 100% owned and operated SAGD project, was completed during Q3/13, on budget, at a cost of approximately $30,000 per flowing barrel. At the end of Q4/13, steam was being circulated in 36 well pairs on 6 pads to initiate the SAGD process. Subsequent to Q4/13, 15 well pairs have been converted to SAGD production as planned. The wells at Kirby South are responding as expected and production is targeted to grow to 40,000 bbl/d in Q4/14. All evaporators, steam generators and oil treating vessels are in service and the first shipment of crude oil produced was delivered during Q4/13 with production averaging 1,500 bbl/d for the quarter. Production ramp up continues as expected, with current production of approximately 7,000 bbl/d.
- The Kirby North Phase 1 project is targeted for Board sanctioning in mid 2014. Detailed engineering is progressing and, currently, is approximately 97% complete.
- Kirby South and Kirby North Phase 1 will contribute to a staged expansion plan for the greater Kirby area. The Company targets to increase Kirby area production volumes, over time, to approximately 140,000 bbl/d. Canadian Natural's current overall thermal in situ development plan targets to increase facility capacity from current levels to approximately 510,000 bbl/d in staged increments over the next 15 years.
- Planned drilling activity for Q1/14 includes 8 net thermal in situ (bitumen) wells, excluding strat and service wells.

Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Natural gas production (MMcf/d)	**1,165**	1,136	1,113	**1,130**	1,198
Net wells targeting natural gas	**11**	10	3	**45**	35
Net successful wells drilled	**11**	10	3	**44**	35
Success rate	**100%**	100%	100%	**98%**	100%

- North America natural gas production averaged 1,130 MMcf/d for the year, and was minimized to a 6% decrease from 2012, due to liquids-rich development at Septimus and minor acquisitions throughout the year. The decrease in production levels reflects natural production declines and Canadian Natural's strategic decision to allocate capital to higher return crude oil projects. During Q4/13 natural gas production averaged 1,165 MMcf/d, a 5% and 3% increase from Q4/12 and Q3/13 levels respectively. The increase in production from last quarter was largely driven by liquids-rich Septimus production.
- The plant expansion at Septimus, the Company's premium liquids-rich natural gas Montney play, was completed during Q3/13. During the first week of September 2013, the newly expanded gas plant reached its production capacity of 125 MMcf/d and approximately 12,200 bbl/d of liquids with the completion of new wells. With high liquids yields and low operating costs of approximately $0.22/Mcfe, Septimus continues to generate excellent returns and significant free cash flow while maximizing the utilization of the plant capacity in 2014.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Crude oil production (bbl/d)					
North Sea	**20,155**	15,522	19,140	**18,334**	19,824
Offshore Africa	**13,379**	16,172	15,762	**15,923**	18,648
Natural gas production (MMcf/d)					
North Sea	**7**	4	1	**4**	2
Offshore Africa	**23**	23	20	**24**	20
Net wells targeting crude oil	**–**	–	–	**1.0**	–
Net successful wells drilled	**–**	–	–	**1.0**	–
Success rate	**–**	–	–	**100%**	–

- International crude oil production averaged 33,534 bbl/d during the quarter, a 6% increase from Q3/13 levels. This increase was primarily as a result of the successful completion of planned turnarounds in the North Sea, offset by decreased Offshore Africa crude oil production in the quarter due to a temporary shut in of the Baobab field in December 2013 as a result of a mooring line failure on the Floating Production Storage and Offloading ("FPSO") vessel. Production in the Baobab field was temporarily reinstated in late January 2014, with final repairs targeted for 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 the program, which is targeted to add 11,000 BOE/d of net production when complete.
- Canadian Natural is in the process of obtaining a drilling rig to undertake the 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 Ghana and plays elsewhere in offshore Africa.

- Block CI-12 is located approximately 35 km west of the Canadian Natural's current production at Espoir and Baobab and Canadian Natural operates with a 60% working interest. The Company shot a 3D seismic program in Q4/13 and the data is currently being processed. Potential exploration drilling is targeted for 2015.
- Canadian Natural has a 36% working interest in Block CI-514. A seismic program has been completed and a drilling rig has been contracted to commence drilling in March 2014, targeting to drill the Lower Cretaceous formations, with structures targeted to contain between 800 million barrels and 1,400 million barrels gross oil originally in place (300 million barrels and 500 million barrels net oil originally in place).

- In September 2012, the UK government announced the implementation of the Brownfield Allowance ("BFA"), which allows for a property development allowance on qualifying preapproved field developments. This allowance partially mitigates the impact of previous supplementary income tax increases. To date, Canadian Natural has received approval for 3 BFAs. The Tiffany field BFA resulted in a 2 well infill drilling program, which achieved first oil in May 2013. The Ninian Field was awarded a BFA; the development plan, which includes 4 new production wells, 4 injectors and 2 well upgrades, commenced in Q4/13.
- In Q4/11 the Banff/Kyle FPSO suffered damage from severe storm conditions and was consequently removed from the field for repair. The FPSO is currently undergoing repairs and is targeted to return to the field during Q3/14. Subsequent to the tie-in of the FPSO, the Banff/Kyle field is targeted to resume 3,500 bbl/d of net light crude oil production.
- During 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in an after-tax gain on sale of exploration and evaluation property of $166 million. In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery. The operator is targeting to commence drilling the first exploration well in Q3/14.
- The decommissioning activities at the Murchison platform commenced in Q4/13 and the Company estimates the decommissioning efforts will continue for approximately 5 years. In October 2013, the Company entered into a Decommissioning Relief Deed ("DRD") with the UK government. The DRD was introduced in 2013 and is a contractual mechanism whereby the UK government guarantees its participation in future field abandonments through a recovery of PRT and corporate income tax.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Synthetic crude oil production (bbl/d)	**112,273**	111,959	83,079	**100,284**	86,077

- Horizon achieved strong and reliable operating performance for all of 2013. Horizon SCO production averaged approximately 112,000 bbl/d in the second half of 2013 upon the completion of the first major turnaround. The Q4/13 production volumes of 112,273 bbl/d represent a 35% increase from Q4/12 levels, indicating a step change in safe, steady and reliable production at Horizon. Canadian Natural expects continued strong operating performance in 2014, and SCO production to date in 2014 has averaged approximately 111,000 bbl/d. Horizon production is targeted to increase by 11% in 2014 from 2013 levels as a result of the continued focus on effective and efficient operations.
- Canadian Natural continues to deliver on its strategy to transition to a longer life, low decline asset base which provides 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 below sanctioned costs.
- An update to the staged Phase 2/3 physical completion of expansion at the end of Q4/13 is as follows:
  - Overall Horizon Phase 2/3 expansion is 34% physically complete.
  - Reliability – Tranche 2 is 94% physically complete. This phase will increase performance, overall production reliability and the Gas Recovery Unit will recover additional light oil barrels in 2014.
  - Directive 74 includes technological investment and research into tailings management. This project remains on track and is physically 24% 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 78% 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 production capacity of approximately 12,000 bbl/d is targeted to occur subsequent to the completion of the coker tie-in.
- Phase 2B is 24% 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 22% 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 trend at or below cost estimates.

▪ On the Phase 2/3 expansion Canadian Natural has committed approximately 60% of the Engineering, Procurement and Construction contracts. In addition, over 50% of the construction contracts have been awarded to date, with 85% being lump sum, ensuring greater cost certainty. To date, Canadian Natural is running approximately 10% below the original cost estimates.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 97.50**	$ 105.82	$ 88.20	**$ 98.00**	$ 94.19
WCS blend differential from WTI (%) (2)	**33%**	16%	21%	**26%**	22%
SCO price (US$/bbl)	**$ 88.37**	$ 109.97	$ 91.90	**$ 98.18**	$ 92.59
Condensate benchmark pricing (US$/bbl)	**$ 94.30**	$ 103.83	$ 98.13	**$ 101.67**	$ 100.92
Average realized pricing before risk management (C$/bbl) (3)	**$ 69.38**	$ 89.24	$ 66.55	**$ 73.81**	$ 72.44
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.99**	$ 2.68	$ 2.89	**$ 3.00**	$ 2.28
Average realized pricing before risk management (C$/Mcf)	**$ 3.62**	$ 3.15	$ 3.42	**$ 3.58**	$ 2.70

(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)**
2013					
October	$ 100.55	26%	$ (2.44)	$ 8.49	$ (1.92)
November	$ 93.93	33%	$ (10.70)	$ 14.03	$ (6.41)
December	$ 97.89	40%	$ (14.30)	$ 12.92	$ (1.38)
2014					
January	$ 94.86	31%	$ (7.12)	$ 13.40	$ 3.35
February	$ 100.68	19%	$ 1.97	$ 8.19	$ 5.15
March*	$ 102.36	21%	$ (0.95)	$ 6.42	$ 3.37

**Based on current indicative pricing as at February 28, 2013.*

- The WCS differential averaged 26% during 2013 compared with 22% in the previous year. During Q4/13 the WCS differential widened to an average of 33% as a result of decreased heavy oil demand due to planned refinery maintenance, pipeline logistical constraints and third party unplanned refinery disruptions. The temporary widening was in line with the Company's Q4/13 expectations. The Company anticipates continued volatility in the WCS differential for the first half of 2014 with a narrowing of the WCS differential thereafter as additional heavy oil conversion and pipeline capacity come on stream.
- WCS differentials to WTI widened to 40% in December. To partially mitigate the cash flow impact from temporarily wider differentials, the Company strategically curtailed production levels by approximately 10,500 bbl/d of primary heavy crude oil production volumes for approximately 30 days. Primary heavy crude oil production volumes were deferred to January and February, when differentials narrowed to 31% and 19% respectively.
- Subsequent to Q4/13, the WCS differential narrowed in January 2014 to average 31%, in February 2014 to average 19% and the indicative differential for March 2014 is approximately 21%. 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 171,000 bbl/d of its heavy crude oil stream to the WCS blend in 2013. The Company remains the largest contributor of the WCS blend, accounting for 59%.
- During 2013, natural gas prices continued to recover from the low pricing levels in 2012. Natural gas prices increased in Q4/13 from Q4/12 due to a return to normal natural gas storage levels. Natural gas prices increased for Q4/13 from Q3/13 due to increased winter weather related natural gas demand and changes in third party short-term tolling arrangements.

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, 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 677,242 BOE/d for Q4/13 with approximately 97% of production located in G8 countries.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 27% and debt to EBITDA of 1.1x at December 31, 2013.
- Canadian Natural maintains significant financial stability and liquidity represented by approximately $2.9 billion of available credit under its bank credit facilities, net of commercial paper issued, as at December 31, 2013. In addition, the Company has negotiated an additional $1 billion committed term facility with the Bank of Montreal, which is available upon closing of the Devon Asset acquisition.
- 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.
- For the year ended December 31, 2013, Canadian Natural has purchased for cancellation under its Normal Course Issuer Bid 10,164,800 common shares at a weighted average price of $31.46 per common share. Subsequent to December 31, 2013, to date in 2014 the Company has purchased for cancellation 1,475,000 common shares at a weighted average price of $35.85 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 April 1, 2014. This increase is in addition to the aggregate quarterly dividend increase of 90% announced during 2013 and is a 13% increase over the previous quarterly dividend. This is the fourteenth consecutive year 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

For 2014, excluding production volumes associated with the Devon Assets, annual production guidance is targeted to average between 521,000 and 560,000 bbl/d of crude oil and NGLs and between 1,170 and 1,210 MMcf/d of natural gas. Q1/14 production guidance before royalties is forecast to average between 469,000 and 495,000 bbl/d of crude oil and NGLs and between 1,166 and 1,186 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.

YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2013 the Company retained Independent Qualified Reserves Evaluators, Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Ltd., to evaluate and review all of the Company's proved and proved plus probable reserves. Sproule evaluated the Company's North America and International crude oil, bitumen, natural gas and NGL reserves. GLJ evaluated the Company's Horizon synthetic crude oil reserves. The Evaluators conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

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

Corporate Total

- Company Gross proved crude oil, SCO, bitumen and NGLs reserves increased 2% to 4.42 billion barrels. Company Gross proved natural gas reserves increased 4% to 4.31 Tcf. Total proved reserves increased 2% to 5.14 billion BOE.
- Company Gross proved plus probable crude oil, SCO, bitumen and NGLs reserves increased 1% to 6.97 billion barrels. Company Gross proved plus probable natural gas reserves increased 6% to 6.11 Tcf. Total proved plus probable reserves increased 1% to 7.99 billion BOE.
- Company Gross proved reserve additions and revisions, including acquisitions, were 266 million barrels of crude oil, SCO, bitumen and NGLs and 592 billion cubic feet of natural gas for 364 million BOE. The total proved reserve replacement ratio was 149%. The total proved reserve life index is 22.8 years.
- Company Gross proved plus probable reserve additions and revisions, including acquisitions, were 227 million barrels of crude oil, bitumen, SCO and NGLs and 745 billion cubic feet of natural gas for 350 million BOE. The total proved plus probable reserve replacement ratio was 143%. The total proved plus probable reserve life index is 35.4 years.
- Proved undeveloped crude oil, SCO, bitumen and NGLs reserves accounted for 30% of the corporate total proved reserves and proved undeveloped natural gas reserves accounted for 4% of the corporate total proved reserves.

North America Exploration and Production

- Company Gross proved crude oil, bitumen and NGLs reserves increased 8% to 1.89 billion barrels. Company Gross proved natural gas reserves increased 4% to 4.16 Tcf. Total proved BOE increased 7% to 2.58 billion barrels.
- Company Gross proved plus probable crude oil, bitumen and NGLs reserves increased 4% to 3.21 billion barrels. Company Gross proved plus probable natural gas reserves increased 6% to 5.88 Tcf. Total proved plus probable BOE increased 4% to 4.19 billion barrels.
- Company Gross proved reserve additions and revisions, including acquisitions, were 268 million barrels of crude oil, bitumen and NGLs and 587 billion cubic feet of natural gas for 366 million BOE. The total proved reserve replacement ratio is 188%. The total proved reserve life index in 14.8 years.
- Company Gross proved plus probable reserve additions and revisions, including acquisitions, were 252 million barrels of crude oil, bitumen and NGLs and 719 billion cubic feet of natural gas for 372 million BOE. The total proved plus probable reserve replacement ratio was 191%. The total proved plus probable reserve life index is 23.9 years.
- Proved undeveloped crude oil, bitumen and NGLs reserves accounted for 37% of the North America total proved reserves and proved undeveloped natural gas reserves accounted for 7% of the North America total proved reserves.
- Thermal oil sands (bitumen) Company Gross proved reserves increased 9% to 1.16 billion barrels primarily due to category transfers from probable undeveloped to proved undeveloped at Kirby North and new proved undeveloped additions at Primrose and Wolf Lake. Proved reserve additions and revisions were 126 million barrels. Total proved plus probable bitumen reserves increased 2% to 2.17 billion barrels.

North America Oil Sands Mining and Upgrading

- Company Gross proved plus probable SCO reserves decreased 2% to 3.29 billion barrels, primarily due to 2013 production, as well as the consumption of distillate, commencing in 2014, to produce on-site diesel fuel and reduce operating costs.

International Exploration and Production

- North Sea Company Gross proved reserves are unchanged at 239 million BOE. North Sea Company Gross proved plus probable reserves are 346 million BOE.
- Offshore Africa Company Gross proved reserves decreased 6% to 108 million BOE primarily due to production. Offshore Africa Company Gross proved plus probable reserves are 170 million BOE.

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

As of December 31, 2013
Forecast Prices and Costs

	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
North America								
Proved								
Developed Producing	95	123	216	321	1,848	2,773	63	3,128
Developed Non-Producing	4	23	1	90	–	251	4	164
Undeveloped	18	98	41	746	363	1,136	43	1,498
Total Proved	117	244	258	1,157	2,211	4,160	110	4,790
Probable	49	90	104	1,013	1,078	1,721	64	2,685
Total Proved plus Probable	166	334	362	2,170	3,289	5,881	174	7,475
North Sea								
Proved								
Developed Producing	38					8		39
Developed Non-Producing	18					63		28
Undeveloped	168					20		172
Total Proved	224					91		239
Probable	101					34		107
Total Proved plus Probable	325					125		346
Offshore Africa								
Proved								
Developed Producing	34					40		41
Developed Non-Producing	–					–		–
Undeveloped	65					14		67
Total Proved	99					54		108
Probable	54					49		62
Total Proved plus Probable	153					103		170
Total Company								
Proved								
Developed Producing	167	123	216	321	1,848	2,821	63	3,208
Developed Non-Producing	22	23	1	90	–	314	4	192
Undeveloped	251	98	41	746	363	1,170	43	1,737
Total Proved	440	244	258	1,157	2,211	4,305	110	5,137
Probable	204	90	104	1,013	1,078	1,804	64	2,854
Total Proved plus Probable	644	334	362	2,170	3,289	6,109	174	7,991

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

As of December 31, 2013
Forecast Prices and Costs

	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
North America								
Proved								
Developed Producing	82	101	164	244	1,564	2,485	45	2,614
Developed Non-Producing	3	19	1	65	–	211	2	125
Undeveloped	15	82	32	574	263	988	34	1,165
Total Proved	100	202	197	883	1,827	3,684	81	3,904
Probable	40	72	71	776	836	1,454	50	2,087
Total Proved plus Probable	140	274	268	1,659	2,663	5,138	131	5,991
North Sea								
Proved								
Developed Producing	38					8		39
Developed Non-Producing	18					63		28
Undeveloped	168					20		172
Total Proved	224					91		239
Probable	101					34		107
Total Proved plus Probable	325					125		346
Offshore Africa								
Proved								
Developed Producing	29					27		34
Developed Non-Producing	–					–		–
Undeveloped	51					11		53
Total Proved	80					38		87
Probable	42					32		47
Total Proved plus Probable	122					70		134
Total Company								
Proved								
Developed Producing	149	101	164	244	1,564	2,520	45	2,687
Developed Non-Producing	21	19	1	65	–	274	2	153
Undeveloped	234	82	32	574	263	1,019	34	1,390
Total Proved	404	202	197	883	1,827	3,813	81	4,230
Probable	183	72	71	776	836	1,520	50	2,241
Total Proved plus Probable	587	274	268	1,659	2,663	5,333	131	6,471

Reconciliation of Company Gross Reserves by Product

As of December 31, 2013
Forecast Prices and Costs

PROVED

North America	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2012	113	204	267	1,066	2,255	3,985	94	4,663
Discoveries	–	1	–	–	–	6	–	2
Extensions	3	36	–	51	–	163	13	130
Infill Drilling	5	11	2	–	–	73	3	33
Improved Recovery	–	1	–	–	–	1	–	1
Acquisitions	9	–	–	–	–	141	2	35
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	1	1	–	2	(2)	(99)	(1)	(16)
Technical Revisions	2	40	5	73	(5)	303	8	173
Production	(16)	(50)	(16)	(35)	(37)	(412)	(9)	(231)
December 31, 2013	117	244	258	1,157	2,211	4,160	110	4,790

North Sea	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2012	227					82		240
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	6					15		8
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(2)					(4)		(2)
Production	(7)					(2)		(7)
December 31, 2013	224					91		239

Offshore Africa	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2012	103					69		115
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	1					(6)		–
Production	(5)					(9)		(7)
December 31, 2013	99					54		108

Total Company	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2012	443	204	267	1,066	2,255	4,136	94	5,018
Discoveries	–	1	–	–	–	6	–	2
Extensions	3	36	–	51	–	163	13	130
Infill Drilling	5	11	2	–	–	73	3	33
Improved Recovery	–	1	–	–	–	1	–	1
Acquisitions	15	–	–	–	–	156	2	43
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	1	1	–	2	(2)	(99)	(1)	(16)
Technical Revisions	1	40	5	73	(5)	293	8	171
Production	(28)	(50)	(16)	(35)	(37)	(423)	(9)	(245)
December 31, 2013	440	244	258	1,157	2,211	4,305	110	5,137

Reconciliation of Company Gross Reserves by Product

As of December 31, 2013
Forecast Prices and Costs

PROBABLE

North America	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2012	51	80	105	1,056	1,096	1,589	44	2,697
Discoveries	–	–	–	–	–	1	1	1
Extensions	2	19	–	49	–	261	20	134
Infill Drilling	1	4	–	–	–	19	–	8
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	3	–	–	–	–	35	–	8
Dispositions	–	–	–	–	–	–	–	–
Economic Factors	1	–	1	(2)	1	18	–	4
Technical Revisions	(9)	(13)	(2)	(90)	(19)	(202)	(1)	(167)
Production	–	–	–	–	–	–	–	–
December 31, 2013	49	90	104	1,013	1,078	1,721	64	2,685

North Sea

North Sea	Light and Medium Oil MMbbl	Natural Gas Bcf	Barrels of Oil Equivalent MMBOE
December 31, 2012	105	20	109
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	–	–	–
Improved Recovery	–	–	–
Acquisitions	1	5	2
Dispositions	–	–	–
Economic Factors	–	–	–
Technical Revisions	(5)	9	(4)
Production	–	–	
December 31, 2013	101	34	107

Offshore Africa

Offshore Africa	Light and Medium Oil MMbbl	Natural Gas Bcf	Barrels of Oil Equivalent MMBOE
December 31, 2012	55	42	62
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	–	–	–
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	(1)	–	(1)
Technical Revisions	–	7	1
Production	–	–	–
December 31, 2013	54	49	62

Total Company

Total Company	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2012	211	80	105	1,056	1,096	1,651	44	2,868
Discoveries	–	–	–	–	–	1	1	1
Extensions	2	19	–	49	–	261	20	134
Infill Drilling	1	4	–	–	–	19	–	8
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	4	–	–	–	–	40	–	10
Dispositions	–	–	–	–	–	–	–	–
Economic Factors	–	–	1	(2)	1	18	–	3
Technical Revisions	(14)	(13)	(2)	(90)	(19)	(186)	(1)	(170)
Production	–	–	–	–	–	–	–	–
December 31, 2013	204	90	104	1,013	1,078	1,804	64	2,854

Reconciliation of Company Gross Reserves by Product

As of December 31, 2013
Forecast Prices and Costs

PROVED PLUS PROBABLE

North America	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2012	164	284	372	2,122	3,351	5,574	138	7,360
Discoveries	–	1	–	–	–	7	1	3
Extensions	5	55	–	100	–	424	33	264
Infill Drilling	6	15	2	–	–	92	3	41
Improved Recovery	–	1	–	–	–	1	–	1
Acquisitions	12	–	–	–	–	176	2	43
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	2	1	1	–	(1)	(81)	(1)	(12)
Technical Revisions	(7)	27	3	(17)	(24)	101	7	6
Production	(16)	(50)	(16)	(35)	(37)	(412)	(9)	(231)
December 31, 2013	166	334	362	2,170	3,289	5,881	174	7,475

North Sea	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2012	332					102		349
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	7					20		10
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	(7)					5		(6)
Production	(7)					(2)		(7)
December 31, 2013	325					125		346

Offshore Africa	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2012	158					111		177
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	(1)					–		(1)
Technical Revisions	1					1		1
Production	(5)					(9)		(7)
December 31, 2013	153					103		170

Total Company	Light and Medium Oil MMbbl	Primary Heavy Oil MMbbl	Pelican Lake Heavy Oil MMbbl	Bitumen (Thermal Oil) MMbbl	Synthetic Crude Oil MMbbl	Natural Gas Bcf	Natural Gas Liquids MMbbl	Barrels of Oil Equivalent MMBOE
December 31, 2012	654	284	372	2,122	3,351	5,787	138	7,886
Discoveries	–	1	–	–	–	7	1	3
Extensions	5	55	–	100	–	424	33	264
Infill Drilling	6	15	2	–	–	92	3	41
Improved Recovery	–	1	–	–	–	1	–	1
Acquisitions	19	–	–	–	–	196	2	53
Dispositions	–	–	–	–	–	(1)	–	–
Economic Factors	1	1	1	–	(1)	(81)	(1)	(13)
Technical Revisions	(13)	27	3	(17)	(24)	107	7	1
Production	(28)	(50)	(16)	(35)	(37)	(423)	(9)	(245)
December 31, 2013	644	334	362	2,170	3,289	6,109	174	7,991

Reserves Notes:

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

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

(3) BOE values may not calculate due to rounding.

(4) Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserve estimates were provided by Sproule Associates Limited:

	2014	*2015*	*2016*	*2017*	*2018*	*Average annual increase thereafter*
Crude oil and NGLs						
WTI at Cushing (US$/bbl)	94.65	88.37	84.25	95.52	96.96	1.50%
Western Canada Select (C$/bbl)	77.81	75.02	75.29	85.36	86.64	1.50%
Edmonton Par (C$/bbl)	92.64	89.31	89.63	101.62	103.14	1.50%
Edmonton Pentanes+ (C$/bbl)	103.50	99.78	100.14	113.53	115.24	1.50%
North Sea Brent (US$/bbl)	108.06	102.73	97.42	106.14	107.73	1.50%
Natural gas						
AECO (C$/MMBtu)	4.00	3.99	4.00	4.93	5.01	1.50%
BC Westcoast Station 2 (C$/MMBtu)	3.95	3.94	3.95	4.88	4.96	1.50%
Henry Hub Louisiana (US$/MMBtu)	4.17	4.15	4.17	5.04	5.12	1.50%

A foreign exchange rate of 0.9400 US$/Cdn$ was used in the 2013 evaluation.

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

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

(7) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

(8) Reserve Life Index is based on the amount for the relevant reserve category divided by the 2014 proved developed producing production forecast prepared by the Independent Qualified Reserve Evaluators.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast, construction of the proposed Energy East pipeline to transport crude oil from Alberta to Quebec and New Brunswick, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia, and the construction and future operations of the North West Redwater bitumen upgrader and refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and natural gas liquids ("NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company’s operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company’s assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management’s estimates or opinions change.

Management’s Discussion and Analysis

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the three months and year ended December 31, 2013 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2012.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company’s unaudited interim consolidated financial statements for the period ended December 31, 2013 and this MD&A have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board. This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, and cash production costs. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the “Financial Highlights” section of this MD&A. The derivation of adjusted cash production costs and adjusted 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 synthetic crude oil.

Production volumes and per unit statistics are presented throughout this MD&A on a “before royalty” or “gross” basis, and realized prices are net of blending costs and exclude the effect of risk management activities. Production on an “after royalty” or “net” basis is also presented for information purposes only.

The Company’s 2014 guidance included in this MD&A does not reflect the potential impact of the agreement announced on February 19, 2014 to acquire certain producing Canadian crude oil and natural gas properties based on a targeted closing date of April 1, 2014.

The following discussion refers primarily to the Company’s financial results for the three months and year ended December 31, 2013 in relation to the comparable periods in 2012 and the third 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, 2012, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated March 5, 2014.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Product sales	**$ 4,330**	$ 5,284	$ 4,059	**$ 17,945**	$ 16,195
Net earnings	**$ 413**	$ 1,168	$ 352	**$ 2,270**	$ 1,892
Per common share – basic	**$ 0.38**	$ 1.07	$ 0.32	**$ 2.08**	$ 1.72
– diluted	**$ 0.38**	$ 1.07	$ 0.32	**$ 2.08**	$ 1.72
Adjusted net earnings from operations (1)	**$ 563**	$ 1,009	$ 359	**$ 2,435**	$ 1,618
Per common share – basic	**$ 0.52**	$ 0.93	$ 0.33	**$ 2.24**	$ 1.48
– diluted	**$ 0.52**	$ 0.93	$ 0.33	**$ 2.23**	$ 1.47
Cash flow from operations (2)	**$ 1,782**	$ 2,454	$ 1,548	**$ 7,477**	$ 6,013
Per common share – basic	**$ 1.64**	$ 2.26	$ 1.41	**$ 6.87**	$ 5.48
– diluted	**$ 1.64**	$ 2.26	$ 1.41	**$ 6.86**	$ 5.47
Capital expenditures, net of dispositions	**$ 2,091**	$ 1,655	$ 1,767	**$ 7,274**	$ 6,308

(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			*Year Ended*	
($ millions)	***Dec 31 2013***	*Sep 30 2013*	*Dec 31 2012*	***Dec 31 2013***	*Dec 31 2012*
Net earnings as reported	***$ 413***	*$ 1,168*	*$ 352*	***$ 2,270***	*$ 1,892*
Share-based compensation, net of tax (1)	***65***	*48*	*(41)*	***135***	*(214)*
Unrealized risk management (gain) loss, net of tax (2)	***(26)***	*99*	*4*	***32***	*(37)*
Unrealized foreign exchange loss (gain), net of tax (3)	***111***	*(75)*	*254*	***226***	*129*
Realized foreign exchange gain on repayment of US dollar debt securities, net of tax (4)	***–***	*–*	*(210)*	***(12)***	*(210)*
Gain on corporate acquisition/disposition of properties, net of tax (5)	***–***	*(231)*	*–*	***(231)***	*–*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (6)	***–***	*–*	*–*	***15***	*58*
Adjusted net earnings from operations	***$ 563***	*$ 1,009*	*$ 359*	***$ 2,435***	*$ 1,618*

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

(5) During the third quarter of 2013, the Company recorded an after-tax gain of $231 million related to the acquisition of Barrick Energy Inc. and the disposition of a 50% working interest in an exploration right in South Africa.

(6) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. During the second quarter of 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013, resulting in an increase in the Company's deferred income tax liability of $15 million. During the third quarter of 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax rate relief on UK North Sea decommissioning expenditures to 50%, resulting in an increase in the Company's deferred income tax liability of $58 million.

Cash Flow from Operations

($ millions)	Three Months Ended Dec 31 2013	Sep 30 2013	Dec 31 2012	Year Ended Dec 31 2013	Dec 31 2012
Net earnings	**$ 413**	$ 1,168	$ 352	**$ 2,270**	$ 1,892
Non-cash items:					
Depletion, depreciation and amortization	**1,272**	1,258	1,213	**4,844**	4,328
Share-based compensation	**65**	48	(41)	**135**	(214)
Asset retirement obligation accretion	**46**	41	38	**171**	151
Unrealized risk management (gain) loss	**(30)**	121	8	**39**	(42)
Unrealized foreign exchange loss (gain)	**111**	(75)	254	**226**	129
Realized foreign exchange gain on repayment of US dollar debt securities	**–**	–	(210)	**(12)**	(210)
Equity loss from joint venture	**1**	1	3	**4**	9
Deferred income tax (recovery) expense	**(96)**	123	(69)	**31**	(30)
Gain on corporate acquisition/disposition of properties	**–**	(289)	–	**(289)**	–
Current income tax on disposition of properties	**–**	58	–	**58**	–
Cash flow from operations	**$ 1,782**	$ 2,454	$ 1,548	**$ 7,477**	$ 6,013

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the year ended December 31, 2013 were $2,270 million compared with $1,892 million for the year ended December 31, 2012. Net earnings for the year ended December 31, 2013 included net after-tax expenses of $165 million compared with net after-tax income of $274 million for the year ended December 31, 2012 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange gain on repayment of long-term debt, the gain on corporate acquisition/disposition of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2013 were $2,435 million compared with $1,618 million for the year ended December 31, 2012.

Net earnings for the fourth quarter of 2013 were $413 million compared with $352 million for the fourth quarter of 2012 and $1,168 million for the third quarter of 2013. Net earnings for the fourth quarter of 2013 included net after-tax expenses of $150 million compared with net after-tax expense of $7 million for the fourth quarter of 2012 and net after-tax income of $159 million for the third quarter of 2013 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange gain on repayment of long-term debt, and the gain on corporate acquisition/disposition of properties. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2013 were $563 million compared with $359 million for the fourth quarter of 2012 and $1,009 million for the third quarter of 2013.

The increase in adjusted net earnings for the year ended December 31, 2013 from the comparable period in 2012 was primarily due to:

- higher crude oil and NGLs and synthetic crude oil (“SCO”) sales volumes in the North America and Oil Sands Mining and Upgrading segments;
- higher realized SCO prices;
- higher natural gas netbacks;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar;

partially offset by:

- higher depletion, depreciation and amortization expense.

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

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGLs sales volumes in the Offshore Africa segment; and
- the impact of a weaker Canadian dollar relative to the US dollar;

partially offset by:

- lower crude oil and NGLs sales volumes in the North America segment.

The decrease in adjusted net earnings for the fourth quarter of 2013 from the third quarter of 2013 was primarily due to:

- lower North America crude oil and NGLs netbacks;
- lower crude oil and NGLs sales volumes in the North America segment; and
- lower realized SCO prices;

partially offset by:

- higher crude oil and NGLs sales volumes in the Offshore Africa segment; and
- the impact of a weaker Canadian dollar relative to the US dollar.

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

Cash flow from operations for the year ended December 31, 2013 was $7,477 million compared with $6,013 million for the year ended December 31, 2012. Cash flow from operations for the fourth quarter of 2013 was $1,782 million compared with $1,548 million for the fourth quarter of 2012 and $2,454 million for the third 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 year ended December 31, 2013 increased 3% to 671,162 BOE/d from 654,665 BOE/d for the year ended December 31, 2012. Total production before royalties for the fourth quarter of 2013 increased 3% to 677,242 BOE/d from 658,973 BOE/d for the fourth quarter of 2012, and decreased 4% from 702,938 BOE/d for the third 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)	**Dec 31 2013**	Sep 30 2013	Jun 30 2013	Mar 31 2013
Product sales	**$ 4,330**	$ 5,284	$ 4,230	$ 4,101
Net earnings	**$ 413**	$ 1,168	$ 476	$ 213
Net earnings per common share				
– basic	**$ 0.38**	$ 1.07	$ 0.44	$ 0.19
– diluted	**$ 0.38**	$ 1.07	$ 0.44	$ 0.19

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

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 strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates, shut-in natural gas production due to pricing and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America, 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, the effect of the planned decommissioning of the Murchison platform in the North Sea, 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			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
WTI benchmark price (US$/bbl)	**$ 97.50**	$ 105.82	$ 88.20	**$ 98.00**	$ 94.19
Dated Brent benchmark price (US$/bbl)	**$ 109.29**	$ 110.35	$ 110.03	**$ 108.62**	$ 111.56
WCS blend differential from WTI (US$/bbl)	**$ 32.21**	$ 17.42	$ 18.15	**$ 25.11**	$ 21.05
WCS blend differential from WTI (%)	**33%**	16%	21%	**26%**	22%
SCO price (US$/bbl)	**$ 88.37**	$ 109.97	$ 91.90	**$ 98.18**	$ 92.59
Condensate benchmark price (US$/bbl)	**$ 94.30**	$ 103.83	$ 98.13	**$ 101.67**	$ 100.92
NYMEX benchmark price (US$/MMBtu)	**$ 3.63**	$ 3.60	$ 3.36	**$ 3.67**	$ 2.80
AECO benchmark price (C$/GJ)	**$ 2.99**	$ 2.68	$ 2.89	**$ 3.00**	$ 2.28
US/Canadian dollar average exchange rate (US$)	**$ 0.9529**	$ 0.9629	$ 1.0088	**$ 0.9710**	$ 1.0004

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$98.00 per bbl for the year ended December 31, 2013, an increase of 4% from US$94.19 per bbl for the year ended December 31, 2012. WTI averaged US$97.50 per bbl for the fourth quarter of 2013, an increase of 11% from US$88.20 per bbl for the fourth quarter of 2012, and a decrease of 8% from US$105.82 per bbl for the third 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$108.62 per bbl for the year ended December 31, 2013, a decrease of 3% from US$111.56 per bbl for the year ended December 31, 2012. Brent averaged US$109.29 per bbl for the fourth quarter of 2013, consistent with the comparable periods.

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. The Brent differential from WTI tightened for the three months and year ended December 31, 2013 from the comparable periods in 2012 due to a continued debottlenecking of logistical constraints from Cushing to the US Gulf Coast. The Brent differential from WTI widened in the fourth quarter of 2013 compared with the third quarter of 2013 due to increased inventory levels at Cushing as well as upward pressure on Brent pricing.

The WCS Heavy Differential averaged 26% for the year ended December 31, 2013 compared with 22% for the year ended December 31, 2012. The WCS Heavy Differential averaged 33% for the fourth quarter of 2013 compared with 21% for the fourth quarter of 2012, and 16% for the third quarter of 2013. The WCS Heavy Differential widened in the fourth quarter of 2013 from the comparable periods as a result of decreased heavy oil demand due to planned refinery maintenance, pipeline logistical constraints and third party unplanned refinery disruptions. To partially mitigate its exposure to fluctuating heavy crude oil differentials, as at December 31, 2013, the Company entered into physical crude oil sales contracts with weighted average fixed WCS differentials as follows: 8,000 bbl/d in the first quarter of 2014 at US$21.89 per bbl; 9,000 bbl/d in the second quarter of 2014 at US$21.93 per bbl; and 10,000 bbl/d in the third and fourth quarters of 2014 at US$20.81 per bbl. Subsequent to December 31, 2013, the WCS Heavy Differential narrowed in January 2014 to average US$29.17 per bbl and in February 2014 to average US$19.14 per bbl. The WCS Heavy Differentials are directionally tightening due to increased demand as a result of third party refinery expansion and higher refinery utilization.

The SCO price averaged US$98.18 per bbl for the year ended December 31, 2013, an increase of 6% from US$92.59 per bbl for the year ended December 31, 2012. The SCO price averaged US$88.37 per bbl for the fourth quarter of 2013, a decrease of 4% from US$91.90 per bbl for the fourth quarter of 2012, and a decrease of 20% from US$109.97 per bbl for the third quarter of 2013. The fluctuations in SCO pricing for the three months and year ended December 31, 2013 from the comparable periods were primarily due to demand fluctuations as well as movements in WTI benchmark pricing.

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

NYMEX natural gas prices averaged US$3.67 per MMBtu for the year ended December 31, 2013, an increase of 31% from US$2.80 per MMBtu for the year ended December 31, 2012. NYMEX natural gas prices averaged US$3.63 per MMBtu for the fourth quarter of 2013, an increase of 8% from US$3.36 per MMBtu for the fourth quarter of 2012, and an increase of 1% from US$3.60 per MMBtu for the third quarter of 2013.

AECO natural gas prices for the year ended December 31, 2013 averaged $3.00 per GJ, an increase of 32% from $2.28 per GJ for the year ended December 31, 2012. AECO natural gas prices for the fourth quarter of 2013 averaged $2.99 per GJ, an increase of 3% from $2.89 per GJ for the fourth quarter of 2012, and an increase of 12% from $2.68 per GJ for the third quarter of 2013.

During the fourth quarter of 2013, natural gas prices continued to recover from the low pricing levels in 2012. Natural gas prices increased for the three months and year ended December 31, 2013 from the comparable periods in 2012 due to a return to normal natural gas storage levels. Natural gas prices increased for the fourth quarter of 2013 from the third quarter of 2013 due to increased winter weather related natural gas demand and changes in third party short-term tolling arrangements.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**332,231**	365,529	351,983	**343,699**	326,829
North America – Oil Sands Mining and Upgrading	**112,273**	111,959	83,079	**100,284**	86,077
North Sea	**20,155**	15,522	19,140	**18,334**	19,824
Offshore Africa	**13,379**	16,172	15,762	**15,923**	18,648
	478,038	509,182	469,964	**478,240**	451,378
Natural gas (MMcf/d)					
North America	**1,165**	1,136	1,113	**1,130**	1,198
North Sea	**7**	4	1	**4**	2
Offshore Africa	**23**	23	20	**24**	20
	1,195	1,163	1,134	**1,158**	1,220
Total barrels of oil equivalent (BOE/d)	**677,242**	702,938	658,973	**671,162**	654,665
Product mix					
Light and medium crude oil and NGLs	**16%**	14%	15%	**15%**	16%
Pelican Lake heavy crude oil	**7%**	6%	5%	**7%**	6%
Primary heavy crude oil	**20%**	20%	20%	**20%**	19%
Bitumen (thermal oil)	**11%**	16%	18%	**14%**	15%
Synthetic crude oil	**17%**	16%	13%	**15%**	13%
Natural gas	**29%**	28%	29%	**29%**	31%
Percentage of product sales (1) (2) (excluding Midstream revenue)					
Crude oil and NGLs	**89%**	93%	90%	**90%**	91%
Natural gas	**11%**	7%	10%	**10%**	9%

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

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**285,594**	299,194	305,577	**287,428**	273,374
North America – Oil Sands Mining and Upgrading	**106,358**	104,627	79,691	**95,098**	82,171
North Sea	**20,106**	15,481	19,096	**18,279**	19,772
Offshore Africa	**11,351**	11,998	10,358	**12,973**	13,628
	423,409	431,300	414,722	**413,778**	388,945
Natural gas (MMcf/d)					
North America	**1,101**	1,109	1,047	**1,080**	1,171
North Sea	**7**	4	1	**4**	2
Offshore Africa	**19**	18	16	**20**	17
	1,127	1,131	1,064	**1,104**	1,190
Total barrels of oil equivalent (BOE/d)	**611,245**	619,800	592,080	**597,835**	587,246

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 year ended December 31, 2013 increased 6% to 478,240 bbl/d from 451,378 bbl/d for the year ended December 31, 2012. Crude oil and NGLs production for the fourth quarter of 2013 increased 2% to 478,038 bbl/d from 469,964 bbl/d for the fourth quarter of 2012 and decreased 6% from 509,182 bbl/d for the third quarter of 2013. The increase in production for the year ended December 31, 2013 from the comparable period in 2012 was primarily due to strong production in Horizon and Pelican Lake and the impact of the drilling program. The increase in production for the fourth quarter of 2013 from the comparable period in 2012 reflected the impact of strong production in Horizon, which was partially offset by lower production from the Company's cyclic thermal operations in the latter half of 2013. The decrease in production for the fourth quarter of 2013 from the third quarter of 2013 was primarily due to decreased production from the Company's cyclic thermal operations, the impact of a third party fuel gas supply interruption in the Woodenhouse area, and a strategic temporary reduction of heavy oil production in the fourth quarter of 2013 due to a wider WCS Heavy Differential. Crude oil and NGLs production in the fourth quarter of 2013 was within the Company's previously issued guidance of 474,000 to 513,000 bbl/d.

Natural gas production for the year ended December 31, 2013 decreased 5% to 1,158 MMcf/d from 1,220 MMcf/d for the year ended December 31, 2012. Natural gas production for the fourth quarter of 2013 increased 5% to 1,195 MMcf/d from 1,134 MMcf/d for the fourth quarter of 2012 and increased 3% from 1,163 MMcf/d for the third quarter of 2013. The decrease in natural gas production for the year ended December 31, 2013 from the comparable period was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines. The increase in natural gas production for the fourth quarter of 2013 from the comparable periods was primarily a result of the completion of the Septimus drilling program and plant facility expansion in the third quarter, as well as the completion of a minor acquisition during the fourth quarter of 2013. Natural gas production in the fourth quarter of 2013 was within the Company's previously issued guidance of 1,195 to 1,205 MMcf/d.

For 2014, annual production guidance is targeted to average between 521,000 and 560,000 bbl/d of crude oil and NGLs and between 1,170 and 1,210 MMcf/d of natural gas. First quarter 2014 production guidance is targeted to average between 469,000 and 495,000 bbl/d of crude oil and NGLs and between 1,166 and 1,186 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2013 increased 5% to average 343,699 bbl/d from 326,829 bbl/d for the year ended December 31, 2012. For the fourth quarter of 2013, crude oil and NGLs production decreased 6% to average 332,231 bbl/d compared with 351,983 bbl/d for the fourth quarter of 2012 and decreased 9% from 365,529 bbl/d for the third quarter of 2013. The increase in crude oil and NGLs production for the year ended December 31, 2013 from the comparable period was primarily due to strong production in Pelican Lake and the impact of the drilling program. The decrease in production for the fourth quarter of 2013 from the comparable periods was primarily due to the decrease in production from the Company's cyclic thermal operations, the impact of a third party fuel gas supply interruption in the Woodenhouse area and a strategic temporary reduction of heavy oil production in the fourth quarter of 2013 due to a wider WCS Heavy Differential. Fourth quarter 2013 production of crude oil and NGLs was within the Company's previously issued guidance of 332,000 to 362,000 bbl/d. First quarter 2014 production guidance is targeted to average between 335,000 and 351,000 bbl/d for crude oil and NGLs.

North America natural gas production for the year ended December 31, 2013 decreased 6% to 1,130 MMcf/d compared with 1,198 MMcf/d for the year ended December 31, 2012. Natural gas production increased 5% to 1,165 MMcf/d for the fourth quarter of 2013 compared with 1,113 MMcf/d in the fourth quarter of 2012 and increased 3% from 1,136 MMcf/d for the third quarter of 2013. The decrease in natural gas production for the year ended December 31, 2013 from the comparable period was primarily a result of a strategic reduction of natural gas drilling as the Company allocated capital to higher return crude oil projects, as well as expected production declines. The increase in natural gas production for the fourth quarter of 2013 from the comparable periods was primarily a result of the completion of the Septimus drilling program and plant facility expansion in the third quarter, as well as the completion of a minor acquisition during the fourth quarter of 2013.

North America – Oil Sands Mining and Upgrading

Production averaged 100,284 bbl/d for the year ended December 31, 2013 compared with 86,077 bbl/d for the year ended December 31, 2012. For the fourth quarter of 2013, SCO production averaged 112,273 bbl/d compared with 83,079 bbl/d for the fourth quarter of 2012 and 111,959 bbl/d for the third quarter of 2013. Production increased for the three months and year ended December 31, 2013 from the comparable periods in 2012, reflecting a continued focus on reliable and efficient operations, and the impact of the successful completion of Horizon's planned maintenance turnaround in May 2013. Production of SCO was within the Company's previously issued guidance of 110,000 to 115,000 bbl/d for the fourth quarter of 2013. First quarter 2014 production guidance is targeted to average between 108,000 and 115,000 bbl/d.

North Sea

North Sea crude oil production for the year ended December 31, 2013 decreased 8% to 18,334 bbl/d from 19,824 bbl/d for the year ended December 31, 2012. Fourth quarter 2013 North Sea crude oil production increased 5% to 20,155 bbl/d from 19,140 bbl/d for the fourth quarter of 2012, and increased 30% from 15,522 bbl/d for the third quarter of 2013. The decrease in production for the year ended December 31, 2013 from the comparable period was primarily due to natural field declines, turnaround activities and a previous reduction in drilling activities as a result of an increase in the UK corporate income tax rate in 2011. The increase in production for the fourth quarter of 2013 from the comparable period in 2012 was due to temporary shut ins of the third-party operated pipeline to the Sullom Voe Terminal, in 2012, which caused all Ninian and associated fields to be shut in for a portion of the fourth quarter of 2012. The increase in production for the fourth quarter of 2013 from the third quarter of 2013 was primarily a result of the successful completion of planned turnarounds during the third quarter of 2013.

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 is currently undergoing repairs and is targeted to be back in the field early in the third quarter of 2014. The associated repair costs, net of insurance recoveries, are not expected to be significant. The financial impact to operations has been partially mitigated through receipt of business interruption insurance proceeds.

Offshore Africa

Offshore Africa crude oil production decreased 15% to 15,923 bbl/d for the year ended December 31, 2013 from 18,648 bbl/d for the year ended December 31, 2012. Fourth quarter 2013 crude oil production averaged 13,379 bbl/d, decreasing 15% from 15,762 bbl/d for the fourth quarter of 2012 and decreasing 17% from 16,172 bbl/d for the third quarter of 2013. The decrease in production volumes for the three months and year ended December 31, 2013 from the comparable periods was due to natural field declines and a temporary shut in of the Baobab field in December 2013 due to a FPSO mooring line failure. Turnaround activities were advanced into this timeframe and production in the Baobab field was reinstated in late January 2014. The Company plans to perform permanent repairs on the mooring lines in March 2014.

International Guidance

The Company's North Sea and Offshore Africa fourth quarter 2013 crude oil production was 33,534 bbl/d and was within the Company's previously issued guidance of 32,000 to 36,000 bbl/d. First quarter 2014 production guidance is targeted to average between 26,000 and 29,000 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)	**Dec 31 2013**	Sep 30 2013	Dec 31 2012
North America – Exploration and Production	**830,673**	499,490	643,758
North America – Oil Sands Mining and Upgrading (SCO)	**1,550,857**	1,172,723	993,627
North Sea	**385,073**	533,155	77,018
Offshore Africa	**185,476**	1,858,081	1,036,509
	2,952,079	4,063,449	2,750,912

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Crude oil and NGLs ($/bbl) (1)					
Sales price (2) (3)	**$ 69.38**	$ 89.24	$ 66.55	**$ 73.81**	$ 72.44
Transportation	**1.84**	2.38	2.32	**2.22**	2.20
Realized sales price, net of transportation	**67.54**	86.86	64.23	**71.59**	70.24
Royalties	**8.82**	15.20	8.59	**11.13**	10.67
Production expense	**18.59**	15.90	15.32	**17.14**	16.11
Netback	**$ 40.13**	$ 55.76	$ 40.32	**$ 43.32**	$ 43.46
Natural gas ($/Mcf) (1)					
Sales price (2) (3)	**$ 3.62**	$ 3.15	$ 3.42	**$ 3.58**	$ 2.70
Transportation	**0.28**	0.27	0.26	**0.28**	0.26
Realized sales price, net of transportation	**3.34**	2.88	3.16	**3.30**	2.44
Royalties	**0.21**	0.10	0.21	**0.18**	0.09
Production expense	**1.37**	1.38	1.43	**1.42**	1.31
Netback	**$ 1.76**	$ 1.40	$ 1.52	**$ 1.70**	$ 1.04
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2) (3)	**$ 53.30**	$ 67.09	$ 51.97	**$ 56.46**	$ 52.85
Transportation	**1.83**	2.18	2.14	**2.10**	2.04
Realized sales price, net of transportation	**51.47**	64.91	49.83	**54.36**	50.81
Royalties	**6.23**	10.35	6.22	**7.74**	7.07
Production expense	**15.04**	13.36	13.11	**14.24**	13.14
Netback	**$ 30.20**	$ 41.20	$ 30.50	**$ 32.38**	$ 30.60

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Crude oil and NGLs ($/bbl) [1] [2] [3]					
North America	**$ 62.70**	$ 87.62	$ 62.68	**$ 69.90**	$ 67.93
North Sea	**$ 113.84**	$ 117.30	$ 109.47	**$ 112.46**	$ 111.90
Offshore Africa	**$ 108.25**	$ 119.48	$ 97.97	**$ 110.21**	$ 111.18
Company average	**$ 69.38**	$ 89.24	$ 66.55	**$ 73.81**	$ 72.44
Natural gas ($/Mcf) [1] [2] [3]					
North America	**$ 3.46**	$ 3.00	$ 3.30	**$ 3.43**	$ 2.57
North Sea	**$ 5.05**	$ 6.12	$ 3.96	**$ 5.69**	$ 5.14
Offshore Africa	**$ 11.13**	$ 10.47	$ 10.39	**$ 10.45**	$ 10.31
Company average	**$ 3.62**	$ 3.15	$ 3.42	**$ 3.58**	$ 2.70
Company average ($/BOE) [1] [2] [3]	**$ 53.30**	$ 67.09	$ 51.97	**$ 56.46**	$ 52.85

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

North America

North America realized crude oil prices increased 3% to average $69.90 per bbl for the year ended December 31, 2013 from $67.93 per bbl for the year ended December 31, 2012. North America realized crude oil prices averaged $62.70 per bbl for the fourth quarter of 2013 and were comparable with $62.68 per bbl for the fourth quarter of 2012 and decreased 28% compared with $87.62 per bbl for the third quarter of 2013. The increase in realized crude oil prices for the year ended December 31, 2013 from the comparable period was due to higher WTI benchmark pricing and the impact of a weaker Canadian dollar relative to the US dollar. The decrease in realized crude oil prices for the fourth quarter of 2013 from the third quarter for 2013 was due to lower benchmark WTI pricing and the widening of the WCS Heavy Differential, partially offset by the impact of a weaker Canadian dollar relative to the US dollar. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2013 contributed approximately 168,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 33% to average $3.43 per Mcf for the year ended December 31, 2013 from $2.57 per Mcf for the year ended December 31, 2012. North America realized natural gas prices increased 5% to average $3.46 per Mcf for the fourth quarter of 2013 compared with $3.30 per Mcf in the fourth quarter of 2012, and increased 15% compared with $3.00 per Mcf for the third quarter of 2013. The increase in realized natural gas prices for the three months and year ended December 31, 2013 from the comparable periods in 2012 was primarily due to a return to normal gas storage levels. The increase in realized natural gas prices for the fourth quarter of 2013 from the third quarter of 2013 was primarily due to seasonal weather related natural gas demand and changes in third party short-term tolling arrangements.

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

(Quarterly Average)	**Dec 31 2013**	Sep 30 2013	Dec 31 2012
Wellhead Price (1) (2) (3)			
Light and medium crude oil and NGLs ($/bbl)	**$ 70.91**	$ 83.10	$ 70.20
Pelican Lake heavy crude oil ($/bbl)	**$ 60.19**	$ 90.32	$ 65.12
Primary heavy crude oil ($/bbl)	**$ 61.75**	$ 89.76	$ 62.02
Bitumen (thermal oil) ($/bbl)	**$ 57.97**	$ 86.68	$ 58.69
Natural gas ($/Mcf)	**$ 3.46**	$ 3.00	$ 3.30

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

North Sea

North Sea realized crude oil prices averaged $112.46 per bbl for the year ended December 31, 2013 and were comparable with $111.90 per bbl for the year ended December 31, 2012. Realized crude oil prices increased 4% to average $113.84 per bbl for the fourth quarter of 2013 from $109.47 per bbl for the fourth quarter of 2012, and decreased 3% from $117.30 per bbl for the third quarter of 2013. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2013 from the comparable periods reflected movements in Brent benchmark pricing, the timing of liftings, and the impact of a weaker Canadian dollar relative to the US dollar.

Offshore Africa

Offshore Africa realized crude oil prices averaged $110.21 per bbl for the year ended December 31, 2013 and were comparable with $111.18 per bbl for the year ended December 31, 2012. Realized crude oil prices increased 10% to average $108.25 per bbl for the fourth quarter of 2013 from $97.97 per bbl for the fourth quarter of 2012, and decreased 9% from $119.48 per bbl for the third quarter of 2013. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2013 from the comparable periods reflected movements in Brent benchmark pricing, the timing of liftings, and the impact of a weaker Canadian dollar relative to the US dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 8.66**	$ 15.65	$ 7.93	**$ 11.30**	$ 10.33
North Sea	**$ 0.28**	$ 0.31	$ 0.25	**$ 0.33**	$ 0.29
Offshore Africa	**$ 16.41**	$ 30.83	$ 33.59	**$ 18.18**	$ 29.46
Company average	**$ 8.82**	$ 15.20	$ 8.59	**$ 11.13**	$ 10.67
Natural gas ($/Mcf) [(1)]					
North America	**$ 0.17**	$ 0.06	$ 0.18	**$ 0.14**	$ 0.06
Offshore Africa	**$ 2.04**	$ 2.06	$ 1.74	**$ 1.83**	$ 1.77
Company average	**$ 0.21**	$ 0.10	$ 0.21	**$ 0.18**	$ 0.09
Company average ($/BOE) [(1)]	**$ 6.23**	$ 10.35	$ 6.22	**$ 7.74**	$ 7.07

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

North America

North America crude oil and natural gas royalties for the year ended December 31, 2013 compared with the year ended December 31, 2012 reflected movements in benchmark commodity prices and the fluctuations of the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 17% of product sales in 2013 compared with 16% in 2012. Crude oil and NGLs royalties averaged approximately 14% of product sales for the fourth quarter of 2013 compared with 13% for the fourth quarter of 2012 and 18% for the third quarter of 2013. The decrease in royalties in the fourth quarter of 2013 from the third quarter of 2013 was primarily due to the decrease in realized crude oil prices. Crude oil and NGLs royalties per bbl are anticipated to average 18% to 20% of product sales for 2014.

Natural gas royalties averaged approximately 5% of product sales in 2013 compared with 3% in 2012. Natural gas royalties averaged approximately 5% of product sales for the fourth quarter of 2013 compared with 6% for the fourth quarter of 2012 and 2% for the third quarter of 2013. The fluctuations in natural gas royalty rates compared with the comparable periods primarily reflected movements in realized natural gas prices. Natural gas royalties are anticipated to average 7% to 8% 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% in 2013 compared with 26% in 2012. Royalty rates as a percentage of product sales averaged approximately 15% for the fourth quarter of 2013 compared with 32% for the fourth quarter of 2012 and 24% for the third quarter of 2013. The fluctuations in royalties from the comparable periods in 2012 were due to adjustments to royalties.

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			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 14.46**	$ 13.04	$ 12.79	**$ 14.20**	$ 13.40
North Sea	**$ 65.41**	$ 78.66	$ 54.41	**$ 66.19**	$ 53.53
Offshore Africa	**$ 29.31**	$ 25.13	$ 22.14	**$ 25.32**	$ 23.11
Company average	**$ 18.59**	$ 15.90	$ 15.32	**$ 17.14**	$ 16.11
Natural gas ($/Mcf) (1)					
North America	**$ 1.32**	$ 1.33	$ 1.40	**$ 1.39**	$ 1.28
North Sea	**$ 4.81**	$ 5.79	$ 3.58	**$ 4.67**	$ 3.75
Offshore Africa	**$ 2.73**	$ 2.82	$ 3.19	**$ 2.53**	$ 2.27
Company average	**$ 1.37**	$ 1.38	$ 1.43	**$ 1.42**	$ 1.31
Company average ($/BOE) (1)	**$ 15.04**	$ 13.36	$ 13.11	**$ 14.24**	$ 13.14

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

North America

North America crude oil and NGLs production expense for the year ended December 31, 2013 increased 6% to $14.20 per bbl from $13.40 per bbl for the year ended December 31, 2012. North America crude oil and NGLs production expense for the fourth quarter of 2013 increased 13% to $14.46 per bbl from $12.79 per bbl for the fourth quarter of 2012 and increased 11% from $13.04 per bbl for the third quarter of 2013. The increase in production expense for the three months and year ended December 31, 2013 from the comparable periods was primarily the result of higher electricity costs, as well as higher servicing costs related to heavy oil activities. North America crude oil and NGLs production expense was slightly higher than the Company's previously issued guidance of $12.00 to $14.00 per bbl, and is anticipated to average $12.50 to $14.50 per bbl for 2014.

North America natural gas production expense for the year ended December 31, 2013 increased 9% to $1.39 per Mcf from $1.28 per Mcf for the year ended December 31, 2012. North America natural gas production expense for the fourth quarter of 2013 decreased 6% to $1.32 per Mcf from $1.40 per Mcf for the fourth quarter of 2012, and was comparable with the third quarter of 2013. Natural gas production expense increased for the year ended December 31, 2013 from the year ended December 31, 2012 primarily due to lower production volumes related to the strategic reduction in natural gas activity. Natural gas production expense decreased for the fourth quarter of 2013 from the comparable periods due to increased production. North America natural gas production expense was within the Company's previously issued guidance of $1.35 to $1.40 per Mcf, and is anticipated to average $1.35 to $1.45 per Mcf for 2014.

North Sea

North Sea crude oil production expense for the year ended December 31, 2013 increased 24% to $66.19 per bbl from $53.53 per bbl for the year ended December 31, 2012. North Sea crude oil production expense for the fourth quarter of 2013 increased 20% to $65.41 per bbl from $54.41 per bbl for the fourth quarter of 2012 and decreased 17% from $78.66 per bbl for the third quarter of 2013. Production expense increased on a per barrel basis for the three months and year ended December 31, 2013 from the comparable periods in 2012 due to production declines on relatively fixed costs. The decrease for the fourth quarter of 2013 from the third quarter of 2013 was due to the impacts of turnaround activities and higher production volumes on a relatively fixed cost structure. North Sea crude oil production expense was slightly higher than the Company's previously issued guidance of $62.00 to $66.00 per bbl. Production expense is anticipated to average $52.00 to $56.00 per bbl for 2014 due to new drilling activities which 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

Offshore Africa crude oil production expense for the year ended December 31, 2013 increased 10% to $25.32 per bbl from $23.11 per bbl for the year ended December 31, 2012. Offshore Africa crude oil production expense for the fourth quarter of 2013 averaged $29.31 per bbl, an increase of 32% from $22.14 per bbl for the fourth quarter of 2012, and an increase of 17% from $25.13 per bbl for the third quarter of 2013. Production expense increased for the three months and year ended December 31, 2013 from the comparable periods in 2012 as a result of production declines on relatively fixed costs and the timing of liftings from various fields, which have different cost structures. The increase for the fourth quarter of 2013 from the third quarter of 2013 was due to timing of liftings from various fields. Offshore Africa crude oil production expense was below the Company's previously issued guidance of $27.00 to $30.00 per bbl, and 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, as well as due to lower production.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Expense ($ millions)	**$ 1,133**	$ 1,089	$ 1,097	**$ 4,254**	$ 3,874
$/BOE (1)	**$ 21.20**	$ 20.33	$ 20.66	**$ 20.38**	$ 18.65

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

Depletion, depreciation and amortization expense increased for the three months and year ended December 31, 2013 from the comparable periods primarily due to the effect of the planned cessation of production and decommissioning of the Murchison platform in the North Sea, fluctuations in sales volumes and higher overall future development costs.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Expense ($ millions)	**$ 38**	$ 32	$ 30	**$ 137**	$ 119
$/BOE (1)	**$ 0.71**	$ 0.61	$ 0.56	**$ 0.66**	$ 0.57

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

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

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. During the fourth quarter of 2013, operating performance continued to be strong, leading to production of 112,273 bbl/d, which was within stated guidance.

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

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2013**	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
SCO sales price (2)	**$ 92.05**	$ 114.19	$ 89.40	**$ 100.75**	$ 90.74
Bitumen value for royalty purposes (3)	**$ 55.45**	$ 82.78	$ 58.12	**$ 65.48**	$ 59.93
Bitumen royalties (4)	**$ 5.06**	$ 6.82	$ 3.80	**$ 5.11**	$ 4.34
Transportation	**$ 1.51**	$ 1.52	$ 2.06	**$ 1.57**	$ 1.83

(1) Amounts expressed on a per unit basis are based on sales volumes excluding the period of turnaround/suspension of production.
(2) Comparative figures have been adjusted to reflect realized product prices before transportation costs.
(3) Calculated as the quarterly average of the bitumen valuation methodology price.
(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices averaged $100.75 per bbl for the year ended December 31, 2013, an increase of 11% compared with $90.74 per bbl for the year ended December 31, 2012. Realized SCO sales prices averaged $92.05 per bbl for the fourth quarter of 2013, an increase of 3% compared with $89.40 per bbl for the fourth quarter of 2012 and an decrease of 19% compared with $114.19 per bbl for the third quarter of 2013, reflecting benchmark pricing and prevailing differentials.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2013**	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Cash production costs	**$ 389**	$ 407	$ 372	**$ 1,567**	$ 1,504
Less: costs incurred during the period of turnaround/suspension of production	**–**	–	–	**(104)**	(154)
Adjusted cash production costs	**$ 389**	$ 407	$ 372	**$ 1,463**	$ 1,350
Adjusted cash production costs, excluding natural gas costs	**$ 362**	$ 380	$ 342	**$ 1,359**	$ 1,254
Adjusted natural gas costs	**27**	27	30	**104**	96
Adjusted cash production costs	**$ 389**	$ 407	$ 372	**$ 1,463**	$ 1,350

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2013**	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Adjusted cash production costs, excluding natural gas costs	**$ 36.31**	$ 37.27	$ 45.31	**$ 37.68**	$ 39.79
Adjusted natural gas costs	**2.74**	2.63	3.96	**2.89**	3.04
Adjusted cash production costs	**$ 39.05**	$ 39.90	$ 49.27	**$ 40.57**	$ 42.83
Sales (bbl/d) (2)	**108,163**	110,750	81,936	**98,757**	86,153

(1) Adjusted cash production costs on a per unit basis were based on sales volumes excluding the period of turnaround/suspension of production.

(2) Sales volumes include the period of turnaround/suspension of production.

Adjusted cash production costs averaged $40.57 per bbl for the year ended December 31, 2013, a decrease of 5% compared with $42.83 per bbl for the year ended December 31, 2012. Adjusted cash production costs for the fourth quarter of 2013 averaged $39.05 per bbl, a decrease of 21% compared with $49.27 per bbl for the fourth quarter of 2012 and a decrease of 2% compared with $39.90 per bbl for the third quarter of 2013 primarily reflecting the impact of strong production volumes on a relatively fixed cost structure. 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

($ millions)	Three Months Ended Dec 31 2013	Sep 30 2013	Dec 31 2012	Year Ended Dec 31 2013	Dec 31 2012
Depletion, depreciation and amortization	**$ 137**	$ 167	$ 114	**$ 582**	$ 447
Less: depreciation incurred during the period of turnaround/suspension of production	**–**	–	–	**(79)**	(6)
Adjusted depletion, depreciation and amortization	**$ 137**	$ 167	$ 114	**$ 503**	$ 441
$/bbl (1)	**$ 13.75**	$ 16.40	$ 15.12	**$ 13.95**	$ 13.99

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

Depletion, depreciation and amortization expense reflected the impact of fluctuations in sales volumes and minor asset derecognitions.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions)	Three Months Ended Dec 31 2013	Sep 30 2013	Dec 31 2012	Year Ended Dec 31 2013	Dec 31 2012
Expense	**$ 8**	$ 9	$ 8	**$ 34**	$ 32
$/bbl (1)	**$ 0.85**	$ 0.83	$ 1.06	**$ 0.94**	$ 1.01

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

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

MIDSTREAM

($ millions)	Three Months Ended Dec 31 2013	Sep 30 2013	Dec 31 2012	Year Ended Dec 31 2013	Dec 31 2012
Revenue	**$ 26**	$ 28	$ 26	**$ 110**	$ 93
Production expense	**8**	9	8	**34**	29
Midstream cash flow	**18**	19	18	**76**	64
Depreciation	**2**	2	2	**8**	7
Equity loss from joint venture	**1**	1	3	**4**	9
Segment earnings before taxes	**$ 15**	$ 16	$ 13	**$ 64**	$ 48

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 December 31, 2013, Redwater Partnership had interim borrowings of $702 million under credit facilities totaling $1,200 million with original maturities no later than December 2017. 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, under its processing agreement, the Company would be obligated to pay its 25% pro rata share of any shortfall.

In December 2013, Redwater Partnership, the Company and APMC agreed in principle to amend 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. 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.

Subsequent to December 31, 2013, the credit facility maturity date was amended to mature on November 28, 2014. 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 March 4, 2014, interim borrowings under the facilities were $857 million.

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2013**	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Expense	**$ 93**	$ 82	$ 64	**$ 335**	$ 270
$/BOE (1)	**$ 1.47**	$ 1.28	$ 1.07	**$ 1.37**	$ 1.13

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

Administration expense for the three months and year ended December 31, 2013 increased from the comparable periods in 2012 primarily due to higher staffing and general corporate costs.

SHARE-BASED COMPENSATION

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2013**	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Expense (recovery)	**$ 65**	$ 48	$ (41)	**$ 135**	$ (214)

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

The Company recorded a $135 million share-based compensation expense for the year ended December 31, 2013, primarily as a result of remeasurement of the fair value of outstanding stock options at the end of the year 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 year. For the year ended December 31, 2013, the Company capitalized $25 million of share-based compensation expense to property, plant and equipment in the Oil Sands Mining and Upgrading segment (December 31, 2012 – $12 million recovery).

For the year ended December 31, 2013, the Company paid $4 million for stock options surrendered for cash settlement (December 31, 2012 – $7 million).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2013**	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Expense, gross	**$ 113**	$ 116	$ 115	**$ 454**	$ 462
Less: capitalized interest	**53**	46	32	**175**	98
Expense, net	**$ 60**	$ 70	$ 83	**$ 279**	$ 364
$/BOE (1)	**$ 0.94**	$ 1.10	$ 1.37	**$ 1.14**	$ 1.52
Average effective interest rate	**4.4%**	4.3%	4.8%	**4.4%**	4.8%

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

Gross interest and other financing expense for the three months and year ended December 31, 2013 was consistent with the comparable periods. Capitalized interest of $175 million for the year ended December 31, 2013 was related to the Horizon Phase 2/3 expansion and the Kirby Thermal Oil Sands Project.

The Company's average effective interest rate for the three months and year ended December 31, 2013 decreased from the comparable periods in 2012 primarily due to 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 and US$350 million of 5.45% notes in the fourth quarter of 2012 as well as due to an increase in the utilization of the lower cost US commercial paper program that was implemented in March 2013. The Company's average effective interest rate for the fourth quarter of 2013 was comparable with the third 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.

($ millions)	Three Months Ended Dec 31 2013	Sep 30 2013	Dec 31 2012	Year Ended Dec 31 2013	Dec 31 2012
Crude oil and NGLs financial instruments	**$ 5**	$ 39	$ 19	**$ 44**	$ 65
Foreign currency contracts	**(41)**	(17)	(27)	**(160)**	97
Realized (gain) loss	**(36)**	22	(8)	**(116)**	162
Crude oil and NGLs financial instruments	**(10)**	57	29	**17**	3
Natural gas financial instruments	**(5)**	8	–	**3**	–
Foreign currency contracts	**(15)**	56	(21)	**19**	(45)
Unrealized (gain) loss	**(30)**	121	8	**39**	(42)
Net (gain) loss	**$ (66)**	$ 143	$ –	**$ (77)**	$ 120

Complete details related to outstanding derivative financial instruments at December 31, 2013 are disclosed in note 14 to the Company's unaudited interim consolidated financial statements.

The Company recorded a net unrealized loss of $39 million ($32 million after-tax) on its risk management activities for the year ended December 31, 2013, including an unrealized gain of $30 million ($26 million after-tax) for the fourth quarter of 2013 (September 30, 2013 – unrealized loss of $121 million; $99 million after-tax; December 31, 2012 – unrealized loss of $8 million; $4 million after-tax).

FOREIGN EXCHANGE

($ millions)	Three Months Ended Dec 31 2013	Sep 30 2013	Dec 31 2012	Year Ended Dec 31 2013	Dec 31 2012
Net realized loss (gain)	**$ 3**	$ 12	$ (196)	**$ (16)**	$ (178)
Net unrealized loss (gain) [1]	**111**	(75)	254	**226**	129
Net loss (gain)	**$ 114**	$ (63)	$ 58	**$ 210**	$ (49)

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

The net realized foreign exchange gain for the year ended December 31, 2013 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$400 million of 5.15% notes in the first quarter of 2013. The net unrealized foreign exchange loss for the year ended December 31, 2013 was primarily related to the impact of a weaker Canadian dollar with respect to remaining US dollar debt and the reversal of the life-to-date unrealized foreign exchange gain on the repayment of US$400 million of 5.15% notes in the first quarter of 2013. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2013 – unrealized gain of $85 million, September 30, 2013 – unrealized loss of $55 million, December 31, 2012 – unrealized gain of $27 million; year ended December 31, 2013 – unrealized gain of $165 million; December 31, 2012 – unrealized loss of $53 million). The US/Canadian dollar exchange rate at December 31, 2013 was US$0.9402 (September 30, 2013 – US$0.9723; December 31, 2012 – US$1.0051).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Dec 31 2013	Three Months Ended Sep 30 2013	Three Months Ended Dec 31 2012	Year Ended Dec 31 2013	Year Ended Dec 31 2012
North America [(1)]	**$ 133**	$ 178	$ 68	**$ 544**	$ 366
North Sea	**5**	–	29	**23**	115
Offshore Africa [(2)]	**55**	76	56	**202**	206
PRT expense (recovery) – North Sea	**5**	(15)	31	**(56)**	44
Other taxes	**4**	8	5	**22**	16
Current income tax expense	**202**	247	189	**735**	747
Deferred income tax (recovery) expense	**(36)**	159	(34)	**163**	–
Deferred PRT recovery – North Sea	**(60)**	(36)	(35)	**(132)**	(30)
Deferred income tax (recovery) expense	**(96)**	123	(69)	**31**	(30)
	106	370	120	**766**	717
Income tax rate and other legislative changes	**–**	–	–	**(15)**	(58)
	$ 106	$ 370	$ 120	**$ 751**	$ 659
Effective income tax rate on adjusted net earnings from operations [(3)]	**21.4%**	27.2%	25.5%	**26.2%**	27.8%

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

The decrease in the effective income tax rate on adjusted net earnings in the fourth quarter of 2013 from the third quarter of 2013 included the impact of deferred income tax recoveries recognized in the Company's North Sea operations.

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.

During the second quarter of 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $15 million.

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

For 2014, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $675 million to $775 million in Canada and recoveries of $40 million to $60 million in North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Dec 31 2013**	Three Months Ended Sep 30 2013	Three Months Ended Dec 31 2012	Year Ended **Dec 31 2013**	Year Ended Dec 31 2012
Exploration and Evaluation					
Net expenditures (proceeds) [2] [3]	**$ 7**	$ (238)	$ 10	**$ (144)**	$ 309
Property, Plant and Equipment					
Net property acquisitions [2]	**61**	174	76	**246**	144
Well drilling, completion and equipping	**600**	566	566	**2,140**	1,902
Production and related facilities	**444**	431	495	**1,878**	1,978
Capitalized interest and other [4]	**34**	29	23	**120**	111
Net expenditures	**1,139**	1,200	1,160	**4,384**	4,135
Total Exploration and Production	**1,146**	962	1,170	**4,240**	4,444
Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**597**	550	423	**2,057**	1,315
Sustaining capital	**28**	41	94	**278**	223
Turnaround costs	**2**	1	5	**100**	21
Capitalized interest and other [4]	**56**	41	19	**157**	51
Total Oil Sands Mining and Upgrading	**683**	633	541	**2,592**	1,610
Midstream	**185**	3	4	**197**	14
Abandonments [5]	**71**	44	41	**207**	204
Head office	**6**	13	11	**38**	36
Total net capital expenditures	**$ 2,091**	$ 1,655	$ 1,767	**$ 7,274**	$ 6,308
By segment					
North America [2]	**$ 1,001**	$ 1,106	$ 1,086	**$ 4,026**	$ 4,126
North Sea	**95**	92	55	**334**	254
Offshore Africa [3]	**50**	(236)	29	**(120)**	64
Oil Sands Mining and Upgrading	**683**	633	541	**2,592**	1,610
Midstream	**185**	3	4	**197**	14
Abandonments [5]	**71**	44	41	**207**	204
Head office	**6**	13	11	**38**	36
Total	**$ 2,091**	$ 1,655	$ 1,767	**$ 7,274**	$ 6,308

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Includes Business Combinations.
(3) Includes proceeds from the Company's disposition of a 50% interest in its exploration right in South Africa.
(4) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(5) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

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

Net capital expenditures for the year ended December 31, 2013 were $7,274 million compared with $6,308 million for the year ended December 31, 2012. Net capital expenditures for the fourth quarter of 2013 were $2,091 million compared with $1,767 million for the fourth quarter of 2012 and $1,655 million for the third quarter of 2013.

The increase in capital expenditures for the year ended December 31, 2013 from the year ended December 31, 2012 was primarily due to the ramp up of Horizon Phase 2/3 site construction activity, the Horizon turnaround completed in the second quarter of 2013, increased well drilling and completions spending, Midstream pipeline construction activity, and the acquisition of Barrick Energy Inc. in the third quarter of 2013, partially offset by the disposition of a 50% working interest in Block 11B/12B in South Africa and the costs associated with the construction of the Kirby South Project. The increase in capital expenditures for the fourth quarter of 2013 from the comparable period in 2012 was primarily due to increases in Horizon Phase 2/3 site construction activity and Midstream pipeline construction activity. The increase in capital expenditures for the fourth quarter of 2013 from the third quarter of 2013 was primarily due to Midstream pipeline construction activity in the fourth quarter, together with the net impact of the disposition of a 50% working interest in Block 11B/12B in South Africa and the acquisition of Barrick Energy Inc. during the third quarter.

During the third quarter of 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in an after-tax gain on sale of exploration and evaluation property of $166 million. In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery.

Subsequent to December 31, 2013, the Company entered into an agreement to acquire certain producing Canadian crude oil and natural gas properties, together with undeveloped land, for total cash consideration of approximately $3,125 million, based on an effective date of January 1, 2014, with a targeted closing date of April 1, 2014. In connection with the agreement, the Company negotiated an additional $1,000 million unsecured bank credit facility with a two-year maturity and with terms similar to the Company's current syndicated credit facilities, which is available upon closing. It is the Company's intention to finance the transaction utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities, including the new unsecured bank credit facility, while maintaining the ongoing dividend program.

Drilling Activity (number of wells)

	Three Months Ended			Year Ended	
	Dec 31 2013	Sep 30 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Net successful natural gas wells	**11**	10	3	**44**	35
Net successful crude oil wells [(1)]	**324**	334	294	**1,117**	1,203
Dry wells	**13**	7	19	**30**	33
Stratigraphic test / service wells	**54**	9	116	**384**	727
Total	**402**	360	432	**1,575**	1,998
Success rate (excluding stratigraphic test / service wells)	**96%**	98%	94%	**97%**	97%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 59% of the total capital expenditures for the year ended December 31, 2013 compared with approximately 69% for the year ended December 31, 2012.

During the fourth quarter of 2013, the Company targeted 11 net natural gas wells, including 5 wells in Northeast British Columbia, 5 wells in Northwest Alberta and 1 well in Northern Plains. The Company also targeted 337 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 259 primary heavy crude oil wells, 12 Pelican Lake heavy crude oil wells, 38 bitumen (thermal oil) wells and 1 light oil well were drilled. Another 27 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall Primrose thermal production for the fourth quarter of 2013 averaged approximately 77,000 bbl/d compared with approximately 121,000 bbl/d for the fourth quarter of 2012 and approximately 109,000 bbl/d for the third quarter of 2013. Production volumes were in line with expectations due to the cyclic nature of thermal production at Primrose.

In the second quarter of 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Company's view is that the cause of the occurrence is mechanical in nature and is working collaboratively with the regulators in the causation review and remediation plans. The Company's near term steaming plan at the Primrose field has been modified, with steaming being restricted in certain areas until the causation review with the regulators is complete.

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. At December 31, 2013, steam was being circulated through 6 pads with well response as expected. Subsequent to December 31, 2013, 15 well pairs have been fully converted to the production stage.

Development of the tertiary recovery conversion projects at Pelican Lake continued and 12 horizontal wells were drilled during the fourth quarter of 2013. Pelican Lake production averaged approximately 46,000 bbl/d for the fourth quarter of 2013 compared with 36,000 bbl/d for the fourth quarter of 2012 and 45,500 bbl/d for the third 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 first quarter of 2014, the Company's overall planned drilling activity in North America is expected to be 248 net crude oil wells, 8 net bitumen wells and 22 net natural gas wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the fourth quarter of 2013 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 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

In September 2012, the UK government announced the implementation of the Brownfield Allowance, which allows for an agreed allowance for certain pre-approved qualifying field developments. This allowance partially mitigates the impact of previous supplementary income tax increases. During 2013, the Company received Brownfield Allowance approvals for the Tiffany and Ninian fields. At the Tiffany field, during the first quarter, the Company completed 1 injection well conversion and drilled 1 production well with production of approximately 1,500 bbl/d, exceeding original forecasted volumes. The Company also commenced drilling in the Ninian field in the fourth quarter of 2013.

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. In October 2013, the Company entered into a Decommissioning Relief Deed ("DRD") with the UK government. The DRD was introduced in 2013 and is a contractual mechanism whereby the UK government guarantees its participation in future field abandonments through a recovery of PRT and corporate income tax.

Offshore Africa

During the fourth quarter of 2013, the Company contracted a drilling rig for a 6 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. At the Espoir field, the Company is seeking a drilling rig and is assessing the opportunity to commence drilling 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 is expected to commence drilling 1 exploratory well in March 2014. 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)	**Dec 31 2013**	Sep 30 2013	Dec 31 2012
Working capital deficit (1)	**$ 1,574**	$ 969	$ 1,264
Long-term debt (2) (3)	**$ 9,661**	$ 9,393	$ 8,736
Share capital	**$ 3,854**	$ 3,765	$ 3,709
Retained earnings	**21,876**	21,720	20,516
Accumulated other comprehensive income	**42**	67	58
Shareholders' equity	**$ 25,772**	$ 25,552	$ 24,283
Debt to book capitalization (3) (4)	**27%**	27%	26%
Debt to market capitalization (3) (5)	**20%**	21%	22%
After-tax return on average common shareholders' equity (6)	**9%**	9%	8%
After-tax return on average capital employed (3) (7)	**7%**	7%	7%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt.
(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.
(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.
(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 December 31, 2013, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2012. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

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

At December 31, 2013, the Company had in place bank credit facilities of $4,801 million, of which approximately $2,937 million, net of commercial paper issuances of $532 million, was available.

At December 31, 2013, the Company has maturities of long-term debt aggregating $912 million over the next 12 months (US$500 million due November 2014, US$350 million due December 2014). It is the Company's intention to retire this indebtedness utilizing cash flow from operations generated in excess of capital expenditures and available bank credit facilities as necessary, while maintaining the ongoing dividend program. On a pro forma basis, reflecting the retirement of this indebtedness, the available credit under its bank credit facilities at December 31, 2013 would amount to $2,025 million.

During the first quarter of 2013, the Company repaid $400 million of 4.50% medium-term notes and US$400 million of 5.15% notes. During the second quarter of 2013, the $3,000 million revolving syndicated credit facility was extended to June 2017. Additionally, the Company issued $500 million of 2.89% medium-term notes due August 2020. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes.

During the fourth quarter of 2013, the Company filed base shelf prospectuses that allow for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until December 2015. If issued, these securities will bear interest as determined at the date of issuance.

Long-term debt was $9,661 million at December 31, 2013, resulting in a debt to book capitalization ratio of 27% (September 30, 2013 – 27%; December 31, 2012 – 26%). This ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from 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 December 31, 2013 are discussed in note 7 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 March 5, 2014, an average of approximately 272,000 bbl/d of currently forecasted 2014 crude oil volumes and approximately 8,000 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. Further details related to the Company’s commodity derivative financial instruments outstanding at December 31, 2013 are discussed in note 14 to the Company’s unaudited interim consolidated financial statements.

Share Capital

As at December 31, 2013, there were 1,087,322,000 common shares outstanding (December 31, 2012 – 1,092,072,000 common shares) and 72,741,000 stock options outstanding. As at March 4, 2014, the Company had 1,090,824,000 common shares outstanding and 69,845,000 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 2013, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange (“TSX”) and the New York Stock Exchange (“NYSE”), during the twelve month period commencing April 2013 and ending April 2014, up to 54,635,116 common shares. The Company’s Normal Course Issuer Bid announced in 2012 expired April 2013.

For the year ended December 31, 2013, the Company purchased 10,164,800 common shares at a weighted average price of $31.46 per common share, for a total cost of $320 million. Retained earnings were reduced by $285 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2013, the Company purchased 1,475,000 common shares at a weighted average price of $35.85 per common share for a total cost of $53 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 December 31, 2013:

($ millions)	2014	2015	2016	2017	2018	Thereafter
Product transportation and pipeline	$ 298	$ 293	$ 225	$ 208	$ 176	$ 1,324
Offshore equipment operating leases and offshore drilling	$ 147	$ 238	$ 81	$ 61	$ 54	$ 17
Long-term debt (1)	$ 1,436	$ 400	$ 931	$ 1,750	$ 426	$ 4,776
Interest and other financing expense (2)	$ 441	$ 405	$ 387	$ 323	$ 270	$ 3,803
Office leases	$ 35	$ 41	$ 42	$ 45	$ 47	$ 321
Other	$ 309	$ 172	$ 71	$ 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 December 31, 2013.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, refer to the MD&A and the audited consolidated financial statements for the year ended December 31, 2012.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgments in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant critical accounting estimates is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2012.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Dec 31 2013**	Dec 31 2012
ASSETS			
Current assets			
Cash and cash equivalents		**$ 16**	$ 37
Accounts receivable		**1,427**	1,197
Inventory		**632**	554
Prepaids and other		**141**	126
		2,216	1,914
Exploration and evaluation assets	4	**2,609**	2,611
Property, plant and equipment	5	**46,487**	44,028
Other long-term assets	6	**442**	427
		$ 51,754	$ 48,980
LIABILITIES			
Current liabilities			
Accounts payable		**$ 637**	$ 465
Accrued liabilities		**2,519**	2,273
Current income taxes		**359**	285
Current portion of long-term debt	7	**1,444**	798
Current portion of other long-term liabilities	8	**275**	155
		5,234	3,976
Long-term debt	7	**8,217**	7,938
Other long-term liabilities	8	**4,348**	4,609
Deferred income taxes		**8,183**	8,174
		25,982	24,697
SHAREHOLDERS' EQUITY			
Share capital	10	**3,854**	3,709
Retained earnings		**21,876**	20,516
Accumulated other comprehensive income	11	**42**	58
		25,772	24,283
		$ 51,754	$ 48,980

Commitments and contingencies (note 15).

Approved by the Board of Directors on March 5, 2014

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Dec 31 2013**	 Dec 31 2012	Year Ended **Dec 31 2013**	 Dec 31 2012
Product sales		**$ 4,330**	$ 4,059	**$ 17,945**	$ 16,195
Less: royalties		**(383)**	(359)	**(1,800)**	(1,606)
Revenue		**3,947**	3,700	**16,145**	14,589
Expenses					
Production		**1,198**	1,072	**4,559**	4,249
Transportation and blending		**645**	738	**2,938**	2,752
Depletion, depreciation and amortization	5	**1,272**	1,213	**4,844**	4,328
Administration		**93**	64	**335**	270
Share-based compensation	8	**65**	(41)	**135**	(214)
Asset retirement obligation accretion	8	**46**	38	**171**	151
Interest and other financing expense		**60**	83	**279**	364
Risk management activities	14	**(66)**	–	**(77)**	120
Foreign exchange loss (gain)		**114**	58	**210**	(49)
Gain on corporate acquisition/disposition of properties	4,5	**–**	–	**(289)**	–
Equity loss from joint venture	6	**1**	3	**4**	9
		3,428	3,228	**13,109**	11,980
Earnings before taxes		**519**	472	**3,036**	2,609
Current income tax expense	9	**202**	189	**735**	747
Deferred income tax (recovery) expense	9	**(96)**	(69)	**31**	(30)
Net earnings		**$ 413**	$ 352	**$ 2,270**	$ 1,892
Net earnings per common share					
Basic	13	**$ 0.38**	$ 0.32	**$ 2.08**	$ 1.72
Diluted	13	**$ 0.38**	$ 0.32	**$ 2.08**	$ 1.72

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended **Dec 31 2013**	 Dec 31 2012	Year Ended **Dec 31 2013**	 Dec 31 2012
Net earnings	**$ 413**	$ 352	**$ 2,270**	$ 1,892
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized (loss) income during the period, net of taxes of $3 million (2012 – $2 million) – three months ended; $nil (2012 – $4 million) – year ended	**(25)**	17	**(4)**	31
Reclassification to net earnings, net of taxes of $nil (2012 – $nil) – three months ended; $nil (2012 – $nil) – year ended	**–**	(3)	**(1)**	(7)
	(25)	14	**(5)**	24
Foreign currency translation adjustment				
Translation of net investment	**–**	(2)	**(11)**	8
Other comprehensive (loss) income, net of taxes	**(25)**	12	**(16)**	32
Comprehensive income	**$ 388**	$ 364	**$ 2,254**	$ 1,924

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended Dec 31 2013	Year Ended Dec 31 2012
Share capital	10		
Balance – beginning of year		**$ 3,709**	$ 3,507
Issued upon exercise of stock options		**130**	194
Previously recognized liability on stock options exercised for common shares		**50**	45
Purchase of common shares under Normal Course Issuer Bid		**(35)**	(37)
Balance – end of year		**3,854**	3,709
Retained earnings			
Balance – beginning of year		**20,516**	19,365
Net earnings		**2,270**	1,892
Purchase of common shares under Normal Course Issuer Bid	10	**(285)**	(281)
Dividends on common shares	10	**(625)**	(460)
Balance – end of year		**21,876**	20,516
Accumulated other comprehensive income	11		
Balance – beginning of year		**58**	26
Other comprehensive (loss) income, net of taxes		**(16)**	32
Balance – end of year		**42**	58
Shareholders' equity		**$ 25,772**	$ 24,283

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Dec 31 2013	Three Months Ended Dec 31 2012	Year Ended Dec 31 2013	Year Ended Dec 31 2012
Operating activities					
Net earnings		**$ 413**	$ 352	**$ 2,270**	$ 1,892
Non-cash items					
Depletion, depreciation and amortization		**1,272**	1,213	**4,844**	4,328
Share-based compensation		**65**	(41)	**135**	(214)
Asset retirement obligation accretion		**46**	38	**171**	151
Unrealized risk management (gain) loss		**(30)**	8	**39**	(42)
Unrealized foreign exchange loss		**111**	254	**226**	129
Realized foreign exchange gain on repayment of US dollar debt securities		**–**	(210)	**(12)**	(210)
Equity loss from joint venture		**1**	3	**4**	9
Deferred income tax (recovery) expense		**(96)**	(69)	**31**	(30)
Gain on corporate acquisition/disposition of properties		**–**	–	**(289)**	–
Current income tax on disposition of properties		**–**	–	**58**	–
Other		**(92)**	(94)	**(19)**	(47)
Abandonment expenditures		**(71)**	(41)	**(207)**	(204)
Net change in non-cash working capital		**563**	202	**(33)**	447
		2,182	1,615	**7,218**	6,209
Financing activities					
Issue of bank credit facilities and commercial paper, net		**52**	592	**803**	172
Issue of medium-term notes, net	7	**–**	–	**98**	498
Repayment of US dollar debt securities		**–**	(344)	**(398)**	(344)
Issue of common shares on exercise of stock options		**65**	30	**130**	194
Purchase of common shares under Normal Course Issuer Bid		**(46)**	(118)	**(320)**	(318)
Dividends on common shares		**(136)**	(115)	**(523)**	(444)
Net change in non-cash working capital		**(6)**	(8)	**(23)**	(37)
		(71)	37	**(233)**	(279)
Investing activities					
Net (expenditures) proceeds on exploration and evaluation assets		**(7)**	(10)	**144**	(309)
Net expenditures on property, plant and equipment		**(2,013)**	(1,716)	**(7,211)**	(5,795)
Current income tax on disposition of properties		**–**	–	**(58)**	–
Investment in other long-term assets		**–**	–	**–**	2
Net change in non-cash working capital		**(93)**	90	**119**	175
		(2,113)	(1,636)	**(7,006)**	(5,927)
(Decrease) increase in cash and cash equivalents		**(2)**	16	**(21)**	3
Cash and cash equivalents – beginning of period		**18**	21	**37**	34
Cash and cash equivalents – end of period		**$ 16**	$ 37	**$ 16**	$ 37
Interest paid		**$ 95**	$ 104	**$ 460**	$ 464
Income taxes paid		**$ 43**	$ 105	**$ 357**	$ 639

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater 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, 2012, except as discussed in note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2012.

2. CHANGES IN ACCOUNTING POLICIES

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

a)
- IFRS 10 "Consolidated Financial Statements" replaced IAS 27 "Consolidated and Separate Financial Statements" (IAS 27 still contains guidance for Separate Financial Statements) and Standing Interpretations Committee ("SIC") 12 "Consolidation – Special Purpose Entities". IFRS 10 establishes the principles for the presentation and preparation of consolidated financial statements. The standard defines the principle of control and establishes control as the basis for consolidation, as well as providing guidance on applying the control principle to determine whether an investor controls an investee.
- IFRS 11 "Joint Arrangements" replaced IAS 31 "Interests in Joint Ventures" and SIC 13 "Jointly Controlled Entities – Non-Monetary Contributions by Venturers". The new standard defines two types of joint arrangements, joint operations and joint ventures. In a joint operation, the parties with joint control have rights to the assets and obligations for the liabilities of the joint arrangement and are required to recognize their proportionate interest in the assets, liabilities, revenues and expenses of the joint arrangement. In a joint venture, the parties have an interest in the net assets of the arrangement and are required to apply the equity method of accounting.
- IFRS 12 "Disclosure of Interests in Other Entities". The standard includes disclosure requirements for investments in subsidiaries, joint arrangements, associates and unconsolidated structured entities.
- The Company adopted these standards retrospectively. Adoption of these standards did not have a material impact on the Company's consolidated financial statements.

b) IFRS 13 "Fair Value Measurement" provides guidance on the application of fair value where its use is already required or permitted by other standards within IFRS. The standard includes a definition of fair value and a single source of fair value measurement and disclosure requirements for use across all IFRSs that require or permit the use of fair value. IFRS 13 was adopted prospectively. As a result of adoption of this standard, the Company has included its own credit risk in measuring the carrying amount of a risk management liability with no material impact on the Company's consolidated financial statements.

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

d) IFRS Interpretation Committee (“IFRIC”) 20 “Stripping Costs in the Production Phase of a Surface Mine” requires overburden removal costs during the production phase to be capitalized and depreciated if the Company can demonstrate that probable future economic benefits will be realized, the costs can be reliably measured, and the Company can identify the component of the ore body for which access has been improved. Adoption of this standard did not have a material impact on the Company’s consolidated financial statements.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In November 2013, the IASB issued amendments to IFRS 9 “Financial Instruments” to provide guidance on hedge accounting and associated disclosures as part of its overall Financial Instruments project to replace IAS 39 “Financial Instruments – Recognition and Measurement”. The new hedge accounting guidance in IFRS 9 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. The new guidance also allows entities to hedge components of non-financial items.

Previous amendments to IFRS 9 replaced the multiple classification and measurement models for financial assets and liabilities with a new model that has only two categories: amortized cost and fair value through profit and loss. Under IFRS 9, fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

As part of the November 2013 amendments to IFRS 9, the IASB removed the January 1, 2015 mandatory effective date, and did not provide a new mandatory effective date. However, entities may still choose to apply IFRS 9 immediately.

Effective January 1, 2014, the Company adopted IFRS 9 with no material impact on the Company’s consolidated financial statements.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2012	$ 2,564	$ –	$ 47	$ –	$ 2,611
Additions	**90**	**–**	**29**	**–**	**119**
Transfers to property, plant and equipment	**(84)**	**–**	**–**	**–**	**(84)**
Disposals	**–**	**–**	**(39)**	**–**	**(39)**
Foreign exchange adjustments	**–**	**–**	**2**	**–**	**2**
At December 31, 2013	**$ 2,570**	**$ –**	**$ 39**	**$ –**	**$ 2,609**

During the third quarter of 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in a pre-tax gain on sale of exploration and evaluation property of $224 million ($166 million after-tax). In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery.

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2012	$ 50,324	$ 4,574	$ 3,045	$ 16,963	$ 312	$ 270	$ 75,488
Additions	**3,630**	**299**	**97**	**2,772**	**196**	**38**	**7,032**
Transfers from E&E assets	**84**	**–**	**–**	**–**	**–**	**–**	**84**
Disposals/derecognitions	**(228)**	**–**	**–**	**(369)**	**–**	**–**	**(597)**
Foreign exchange adjustments and other	**–**	**327**	**214**	**–**	**–**	**–**	**541**
At December 31, 2013	**$ 53,810**	**$ 5,200**	**$ 3,356**	**$ 19,366**	**$ 508**	**$ 308**	**$ 82,548**
Accumulated depletion and depreciation							
At December 31, 2012	$ 24,991	$ 2,709	$ 2,273	$ 1,202	$ 103	$ 182	$ 31,460
Expense	**3,551**	**548**	**134**	**582**	**8**	**21**	**4,844**
Disposals/derecognitions	**(228)**	**–**	**–**	**(369)**	**–**	**–**	**(597)**
Foreign exchange adjustments and other	**1**	**210**	**144**	**(1)**	**–**	**–**	**354**
At December 31, 2013	**$ 28,315**	**$ 3,467**	**$ 2,551**	**$ 1,414**	**$ 111**	**$ 203**	**$ 36,061**
Net book value							
– at December 31, 2013	**$ 25,495**	**$ 1,733**	**$ 805**	**$ 17,952**	**$ 397**	**$ 105**	**$ 46,487**
– at December 31, 2012	$ 25,333	$ 1,865	$ 772	$ 15,761	$ 209	$ 88	$ 44,028

Project costs not subject to depletion and depreciation	**2013**	2012
Horizon	**$ 4,051**	$ 2,066
Kirby Thermal Oil Sands	**$ 1,532**	$ 1,021

During 2013, the Company acquired a number of producing crude oil and natural gas properties in the North American and North Sea Exploration and Production segments, including properties from the acquisition of Barrick Energy Inc. effective July 31, 2013, for total cash consideration of $252 million (year ended December 31, 2012 – $144 million). These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company assumed associated asset retirement obligations of $131 million (year ended December 31, 2012 – $12 million) and recognized net deferred tax assets of $75 million (year ended December 31, 2012 – $nil) related to temporary differences in the carrying amount of the acquired properties and their tax bases. Interests in jointly controlled assets were acquired with full tax basis. No debt obligations were assumed. The Company recognized after-tax gains of $65 million (year ended December 31, 2012 – $nil) on these acquisitions.

Subsequent to December 31, 2013, the Company entered into an agreement to acquire certain producing Canadian crude oil and natural gas properties, together with undeveloped land, for total cash consideration of approximately $3,125 million, based on an effective date of January 1, 2014, with a targeted closing date of April 1, 2014. In connection with the agreement, the Company negotiated an additional $1,000 million unsecured bank credit facility with a two-year maturity and with terms similar to the Company's current syndicated credit facilities, which is available upon closing.

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. During 2013, pre-tax interest of $175 million (December 31, 2012 – $98 million) was capitalized to property, plant and equipment using a capitalization rate of 4.4% (December 31, 2012 – 4.8%).

6. OTHER LONG-TERM ASSETS

		Dec 31 2013		Dec 31 2012
Investment in North West Redwater Partnership	$	306	$	310
Other		136		117
	$	442	$	427

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 December 31, 2013, Redwater Partnership had interim borrowings of $702 million under credit facilities totaling $1,200 million with original maturities no later than December 2017. 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, under its processing agreement, the Company would be obligated to pay its 25% pro rata share of any shortfall.

In December 2013, Redwater Partnership, the Company and APMC agreed in principle to amend 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. 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.

Subsequent to December 31, 2013, the credit facility maturity date was amended to mature on November 28, 2014. 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 March 4, 2014, interim borrowings under the facilities were $857 million.

7. LONG-TERM DEBT

	Dec 31 2013	Dec 31 2012
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 1,246**	$ 971
Medium-term notes	**1,400**	1,300
	2,646	2,271
US dollar denominated debt, unsecured		
Commercial paper (December 31, 2013 – US$500 million; December 31, 2012 – US$nil)	**532**	–
US dollar debt securities (December 31, 2013 – US$6,150 million; December 31, 2012 – US$6,550 million)	**6,541**	6,517
Less: original issue discount on US dollar debt securities (1)	**(18)**	(20)
	7,055	6,497
Fair value impact of interest rate swaps on US dollar debt securities (2)	**9**	19
	7,064	6,516
Long-term debt before transaction costs	**9,710**	8,787
Less: transaction costs (1) (3)	**(49)**	(51)
	9,661	8,736
Less: current portion of commercial paper	**532**	–
current portion of other long-term debt (1) (2) (3)	**912**	798
	$ 8,217	$ 7,938

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

(2) The carrying amount of US$350 million of 4.90% notes due December 2014 was adjusted by $9 million (December 31, 2012 – $19 million) to reflect the fair value impact of hedge accounting.

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

Bank Credit Facilities and Commercial Paper

As at December 31, 2013, the Company had in place bank credit facilities of $4,801 million, comprised of:

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

During the second quarter of 2013, the $3,000 million revolving syndicated credit facility was extended to June 2017. Each of the $3,000 million and $1,500 million facilities is extendible annually for one-year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

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

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2013, was 1.9% (December 31, 2012 – 2.2%), and on long-term debt outstanding for the year ended December 31, 2013 was 4.4% (December 31, 2012 – 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $395 million, including a $65 million financial guarantee related to Horizon and $226 million of letters of credit related to North Sea operations, were outstanding at December 31, 2013.

Medium-Term Notes

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

During the second quarter of 2013, the Company issued $500 million of 2.89% medium-term notes due August 2020. Proceeds from the securities issued were used to repay bank indebtedness and for general corporate purposes.

During the fourth quarter of 2013, the Company filed a base shelf prospectus 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 2013, the Company repaid US$400 million of 5.15% notes.

During the fourth quarter of 2013, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

8. OTHER LONG-TERM LIABILITIES

	Dec 31 2013	Dec 31 2012
Asset retirement obligations	**$ 4,162**	$ 4,266
Share-based compensation	**260**	154
Risk management (note 14)	**136**	257
Other	**65**	87
	4,623	4,764
Less: current portion	**275**	155
	$ 4,348	$ 4,609

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.0% (December 31, 2012 – 4.3%). A reconciliation of the discounted asset retirement obligations is as follows:

	Dec 31 2013	Dec 31 2012
Balance – beginning of year	**$ 4,266**	$ 3,577
Liabilities incurred	**62**	51
Liabilities acquired	**131**	12
Liabilities settled	**(207)**	(204)
Asset retirement obligation accretion	**171**	151
Revision of estimates	**375**	384
Change in discount rate	**(723)**	315
Foreign exchange adjustments	**87**	(20)
Balance – end of year	**$ 4,162**	$ 4,266

Share-Based Compensation

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

	Dec 31 2013	Dec 31 2012
Balance – beginning of year	**$ 154**	$ 432
Share-based compensation expense (recovery)	**135**	(214)
Cash payment for stock options surrendered	**(4)**	(7)
Transferred to common shares	**(50)**	(45)
Capitalized to (recovered from) Oil Sands Mining and Upgrading	**25**	(12)
Balance – end of year	**260**	154
Less: current portion	**216**	129
	$ 44	$ 25

9. INCOME TAXES

The provision for income tax is as follows:

	Three Months Ended		Year Ended	
	Dec 31 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Current corporate income tax – North America	**$ 133**	$ 68	**$ 544**	$ 366
Current corporate income tax – North Sea	**5**	29	**23**	115
Current corporate income tax – Offshore Africa	**55**	56	**202**	206
Current PRT [1] expense (recovery) – North Sea	**5**	31	**(56)**	44
Other taxes	**4**	5	**22**	16
Current income tax expense	**202**	189	**735**	747
Deferred corporate income tax (recovery) expense	**(36)**	(34)	**163**	–
Deferred PRT [1] recovery – North Sea	**(60)**	(35)	**(132)**	(30)
Deferred income tax (recovery) expense	**(96)**	(69)	**31**	(30)
Income tax expense	**$ 106**	$ 120	**$ 766**	$ 717

(1) Petroleum Revenue Tax.

During the second quarter of 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $15 million.

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

10. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued common shares	Year Ended Dec 31, 2013 **Number of shares** (thousands)		**Amount**
Balance – beginning of year	**1,092,072**	**$**	**3,709**
Issued upon exercise of stock options	**5,415**		**130**
Previously recognized liability on stock options exercised for common shares	**–**		**50**
Purchase of common shares under Normal Course Issuer Bid	**(10,165)**		**(35)**
Balance – end of year	**1,087,322**	**$**	**3,854**

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 set 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 announced on November 5, 2013.

Normal Course Issuer Bid

In April 2013, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the twelve month period commencing April 2013 and ending April 2014, up to 54,635,116 common shares. The Company's Normal Course Issuer Bid announced in 2012 expired April 2013.

For the year ended December 31, 2013, the Company purchased for cancellation 10,164,800 common shares at a weighted average price of $31.46 per common share, for a total cost of $320 million. Retained earnings were reduced by $285 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2013, the Company purchased 1,475,000 common shares at a weighted average price of $35.85 per common share for a total cost of $53 million.

Stock Options

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

	Year Ended Dec 31, 2013 **Stock options** (thousands)		**Weighted average exercise price**
Outstanding – beginning of year	**73,747**	**$**	**34.13**
Granted	**17,823**	**$**	**32.51**
Surrendered for cash settlement	**(401)**	**$**	**23.83**
Exercised for common shares	**(5,415)**	**$**	**24.03**
Forfeited	**(13,013)**	**$**	**34.93**
Outstanding – end of year	**72,741**	**$**	**34.36**
Exercisable – end of year	**26,632**	**$**	**35.27**

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.

11. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Dec 31 2013	Dec 31 2012
Derivative financial instruments designated as cash flow hedges	**$ 81**	$ 86
Foreign currency translation adjustment	**(39)**	(28)
	$ 42	$ 58

12. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2013, the ratio was within the target range at 27%.

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

	Dec 31 2013	Dec 31 2012
Long-term debt [(1)]	**$ 9,661**	$ 8,736
Total shareholders' equity	**$ 25,772**	$ 24,283
Debt to book capitalization	**27%**	26%

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

13. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Weighted average common shares outstanding – basic (thousands of shares)	**1,086,271**	1,093,925	**1,088,682**	1,097,084
Effect of dilutive stock options (thousands of shares)	**1,739**	1,604	**1,859**	2,435
Weighted average common shares outstanding – diluted (thousands of shares)	**1,088,010**	1,095,529	**1,090,541**	1,099,519
Net earnings	**$ 413**	$ 352	**$ 2,270**	$ 1,892
Net earnings per common share – basic	**$ 0.38**	$ 0.32	**$ 2.08**	$ 1.72
– diluted	**$ 0.38**	$ 0.32	**$ 2.08**	$ 1.72

14. FINANCIAL INSTRUMENTS

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

	Dec 31, 2013				
Asset (liability)	**Loans and receivables at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,427**	**$ –**	**$ –**	**$ –**	**$ 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)**

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

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

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

	Dec 31, 2013		
	Carrying amount	**Fair value**	
Asset (liability) (1)		**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)**

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

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

(2) The carrying amount of US$350 million of 4.90% notes due December 2014 was adjusted by $9 million (December 31, 2012 – $19 million) to reflect the fair value impact of hedge accounting.

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

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

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

Asset (liability)		**Dec 31, 2013**		Dec 31, 2012
Derivatives held for trading				
Crude oil price collars	**$**	**(33)**	$	(16)
Foreign currency forward contracts		**(3)**		20
Natural gas AECO basis swaps		**(1)**		–
Natural gas AECO put options, net of put premium financing obligations		**(2)**		–
Cash flow hedges				
Foreign currency forward contracts		**(1)**		–
Cross currency swaps		**(96)**		(261)
	$	**(136)**	$	(257)
Included within:				
Current portion of other long-term liabilities	**$**	**(38)**	$	(4)
Other long-term liabilities		**(98)**		(253)
	$	**(136)**	$	(257)

During 2013, the Company recognized a gain of $4 million (December 31, 2012 – gain of $1 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)		**Dec 31, 2013**		Dec 31, 2012
Balance – beginning of year	**$**	**(257)**	$	(274)
Cost of outstanding put options		**9**		–
Net change in fair value of outstanding derivative financial instruments attributable to:				
Risk management activities		**(39)**		42
Foreign exchange		**165**		(53)
Other comprehensive income		**(5)**		28
		(127)		(257)
Add: put premium financing obligations (1)		**(9)**		–
Balance – end of year		**(136)**		(257)
Less: current portion		**(38)**		(4)
	$	**(98)**	$	(253)

(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		Year Ended	
	Dec 31 2013	Dec 31 2012	**Dec 31 2013**	Dec 31 2012
Net realized risk management (gain) loss	**$ (36)**	$ (8)	**$ (116)**	$ 162
Net unrealized risk management (gain) loss	**(30)**	8	**39**	(42)
	$ (66)	$ –	**$ (77)**	$ 120

Financial Risk Factors

a) Market risk

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

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At December 31, 2013, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Price collars [(1)]	Jan 2014 – Jun 2014	50,000 bbl/d	US$80.00 – US$123.09	Brent
	Jan 2014 – Dec 2014	50,000 bbl/d	US$75.00 – US$121.57	Brent
	Jan 2014 – Dec 2014	50,000 bbl/d	US$80.00 – US$120.17	Brent
	Jan 2014 – Dec 2014	50,000 bbl/d	US$90.00 – US$120.10	Brent
	Jan 2015 – Dec 2015	2,000 bbl/d	US$80.00 – US$122.55	Brent
	Jan 2014 – Jun 2014	50,000 bbl/d	US$80.00 – US$107.84	WTI
	Jan 2014 – Dec 2014	50,000 bbl/d	US$75.00 – US$105.54	WTI

(1) Subsequent to December 31, 2013, the Company entered into an additional 50,000 bbl/d of US$80.00 – US$122.09 Brent collars for the period July 2014 to September 2014 and an additional 6,000 bbl/d of US$80.00 – US$122.52 Brent collars for the period January 2015 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
AECO put options [(1)]	Apr 2014 – Oct 2014	470,000 GJ/d	$3.10	AECO

(1) Subsequent to December 31, 2013, the Company entered into an additional 280,000 GJ/d of $3.10 AECO put options for the period April 2014 to October 2014 for a total cost of $6 million.

The cost of outstanding put options and their respective periods of settlement as at December 31, 2013 are as follows:

	Q2 2014	Q3 2014	Q4 2014
Cost	$4	$4	$1

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 December 31, 2013, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies 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 December 31, 2013, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency					
Swaps	Jan 2014 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2014 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2014 – Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2014 – Mar 2038	US$550	1.170	6.25%	5.76%

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

In addition to the cross currency swap contracts noted above, at December 31, 2013, the Company had US$2,237 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 December 31, 2013, substantially all of the Company's accounts receivable were due within normal trade terms.

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

c) Liquidity risk

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

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

The maturity dates for financial liabilities are as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	637	$	–	$	–	$	–
Accrued liabilities	$	2,519	$	–	$	–	$	–
Risk management	$	38	$	35	$	44	$	19
Other long-term liabilities	$	21	$	35	$	–	$	–
Long-term debt (1)	$	1,436	$	400	$	3,107	$	4,776

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

15. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

		2014		2015		2016		2017		2018		Thereafter
Product transportation and pipeline	$	298	$	293	$	225	$	208	$	176	$	1,324
Offshore equipment operating leases and offshore drilling	$	147	$	238	$	81	$	61	$	54	$	17
Office leases	$	35	$	41	$	42	$	45	$	47	$	321
Other	$	309	$	172	$	71	$	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 a defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

16. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	Exploration and Production															
	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2013	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Segmented product sales	**2,833**	3,006	**12,659**	11,607	**229**	215	**805**	928	**335**	158	**824**	773	**3,397**	3,379	**14,288**	13,308
Less: royalties	**(281)**	(277)	**(1,477)**	(1,268)	**–**	–	**(2)**	(2)	**(52)**	(53)	**(137)**	(199)	**(333)**	(330)	**(1,616)**	(1,469)
Segmented revenue	**2,552**	2,729	**11,182**	10,339	**229**	215	**803**	926	**283**	105	**687**	574	**3,064**	3,049	**12,672**	11,839
Segmented expenses																
Production	**578**	557	**2,351**	2,165	**134**	100	**431**	402	**91**	39	**191**	163	**803**	696	**2,973**	2,730
Transportation and blending	**647**	735	**2,939**	2,735	**2**	2	**6**	10	**–**	–	**1**	1	**649**	737	**2,946**	2,746
Depletion, depreciation and amortization	**905**	965	**3,568**	3,413	**184**	74	**552**	296	**44**	58	**134**	165	**1,133**	1,097	**4,254**	3,874
Asset retirement obligation accretion	**23**	21	**92**	85	**9**	7	**35**	27	**6**	2	**10**	7	**38**	30	**137**	119
Realized risk management activities	**(36)**	(8)	**(116)**	162	**–**	–	**–**	–	**–**	–	**–**	–	**(36)**	(8)	**(116)**	162
Gain on corporate acquisition/disposition of properties	**–**	–	**(65)**	–	**–**	–	**–**	–	**–**	–	**(224)**	–	**–**	–	**(289)**	–
Equity loss from joint venture	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**2,117**	2,270	**8,769**	8,560	**329**	183	**1,024**	735	**141**	99	**112**	336	**2,587**	2,552	**9,905**	9,631
Segmented earnings (loss) before the following	**435**	459	**2,413**	1,779	**(100)**	32	**(221)**	191	**142**	6	**575**	238	**477**	497	**2,767**	2,208
Non–segmented expenses																
Administration																
Share–based compensation																
Interest and other financing expense																
Unrealized risk management activities																
Foreign exchange loss (gain)																
Total non–segmented expenses																
Earnings before taxes																
Current income tax expense																
Deferred income tax (recovery) expense																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter–segment elimination and other				Total			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2013	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Segmented product sales	**915**	675	**3,631**	2,871	**26**	26	**110**	93	**(8)**	(21)	**(84)**	(77)	**4,330**	4,059	**17,945**	16,195
Less: royalties	**(50)**	(29)	**(184)**	(137)	**–**	–	**–**	–	**–**	–	**–**	–	**(383)**	(359)	**(1,800)**	(1,606)
Segmented revenue	**865**	646	**3,447**	2,734	**26**	26	**110**	93	**(8)**	(21)	**(84)**	(77)	**3,947**	3,700	**16,145**	14,589
Segmented expenses																
Production	**389**	372	**1,567**	1,504	**8**	8	**34**	29	**(2)**	(4)	**(15)**	(14)	**1,198**	1,072	**4,559**	4,249
Transportation and blending	**15**	15	**63**	61	**–**	–	**–**	–	**(19)**	(14)	**(71)**	(55)	**645**	738	**2,938**	2,752
Depletion, depreciation and amortization	**137**	114	**582**	447	**2**	2	**8**	7	**–**	–	**–**	–	**1,272**	1,213	**4,844**	4,328
Asset retirement obligation accretion	**8**	8	**34**	32	**–**	–	**–**	–	**–**	–	**–**	–	**46**	38	**171**	151
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(36)**	(8)	**(116)**	162
Gain on corporate acquisition/disposition of properties	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(289)**	–
Equity loss from joint venture	**–**	–	**–**	–	**1**	3	**4**	9	**–**	–	**–**	–	**1**	3	**4**	9
Total segmented expenses	**549**	509	**2,246**	2,044	**11**	13	**46**	45	**(21)**	(18)	**(86)**	(69)	**3,126**	3,056	**12,111**	11,651
Segmented earnings (loss) before the following	**316**	137	**1,201**	690	**15**	13	**64**	48	**13**	(3)	**2**	(8)	**821**	644	**4,034**	2,938
Non–segmented expenses																
Administration													**93**	64	**335**	270
Share–based compensation													**65**	(41)	**135**	(214)
Interest and other financing expense													**60**	83	**279**	364
Unrealized risk management activities													**(30)**	8	**39**	(42)
Foreign exchange loss (gain)													**114**	58	**210**	(49)
Total non–segmented expenses													**302**	172	**998**	329
Earnings before taxes													**519**	472	**3,036**	2,609
Current income tax expense													**202**	189	**735**	747
Deferred income tax (recovery) expense													**(96)**	(69)	**31**	(30)
Net earnings													**413**	352	**2,270**	1,892

Capital Expenditures [1]

	Year Ended					
	Dec 31, 2013			Dec 31, 2012		
	Net expenditures	**Non-cash and fair value changes**[2]	**Capitalized costs**	Net expenditures	Non-cash and fair value changes[2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ 90**	**$ (84)**	**$ 6**	$ 295	$ (173)	$ 122
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa [3]	**(10)**	**–**	**(10)**	14	–	14
	$ 80	**$ (84)**	**$ (4)**	$ 309	$ (173)	$ 136
Property, plant and equipment						
Exploration and Production						
North America	**$ 3,936**	**$ (450)**	**$ 3,486**	$ 3,831	$ 373	$ 4,204
North Sea	**334**	**(35)**	**299**	254	263	517
Offshore Africa	**114**	**(17)**	**97**	50	17	67
	4,384	**(502)**	**3,882**	4,135	653	4,788
Oil Sands Mining and Upgrading [4]	**2,592**	**(189)**	**2,403**	1,610	142	1,752
Midstream	**197**	**(1)**	**196**	14	–	14
Head office	**38**	**–**	**38**	36	–	36
	$ 7,211	**$ (692)**	**$ 6,519**	$ 5,795	$ 795	$ 6,590

(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) The above noted figures do not include the impact of a pre-tax gain on sale of exploration and evaluation assets totaling $224 million on the Company's disposition of a 50% interest in its exploration right in South Africa during 2013.

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

Segmented Assets

	Total Assets	
	Dec 31 2013	Dec 31 2012
Exploration and Production		
North America	**$ 29,234**	$ 29,012
North Sea	**1,964**	1,993
Offshore Africa	**981**	924
Other	**25**	36
Oil Sands Mining and Upgrading	**18,604**	16,291
Midstream	**841**	636
Head office	**105**	88
	$ 51,754	$ 48,980

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated 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 December 31, 2013:

Interest coverage (times)	
Net earnings (1)	7.7x
Cash flow from operations (2)	18.8x

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

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

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, March 6, 2014. The North American conference call number is 1-800-565-0813 and the outside North American conference call number is 001-416-340-8527. Please call in about 10 minutes before the starting time in order to be patched into the call.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Thursday, March 13, 2014. To access the rebroadcast in North America, dial 1-800-408-3053. Those outside of North America, dial 001-905-694-9451. The pass code to use is 9268845.

WEBCAST

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

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