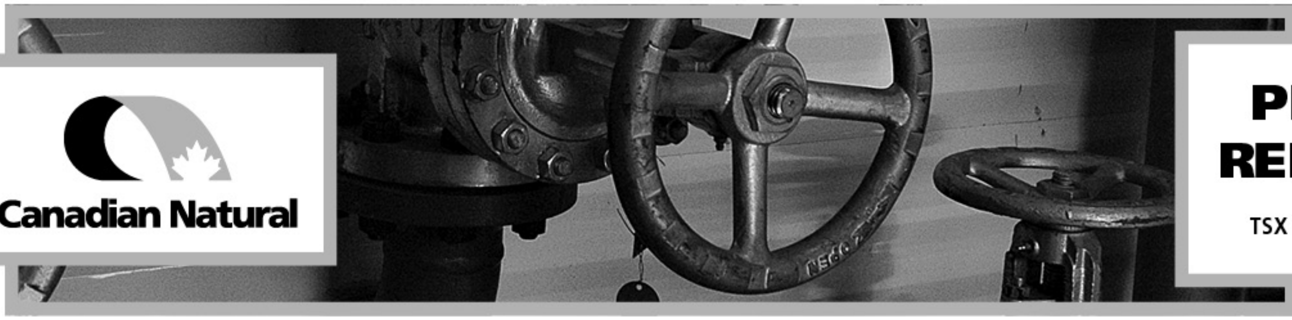
Canadian Natural



PRESS RELEASE

TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2014 FOURTH QUARTER AND YEAR END RESULTS CALGARY, ALBERTA – MARCH 5, 2015 – FOR IMMEDIATE RELEASE

Commenting on fourth quarter and year end results, Steve Laut, President of Canadian Natural, stated, “2014 demonstrated the strength of our diverse and balanced asset base, and our ability to create long-term value for Canadian Natural’s shareholders. At the end of the year, we increased Company Gross total proved plus probable reserves to 8.89 billion BOE, replacing 413% of production, with a proved plus probable reserve life index of approximately 31 years. Our annual average production volumes reached record levels and annual operating costs were optimized as compared to 2013 levels after successfully integrating the acquisition of higher cost production volumes in the first half of 2014.

Our transformation to a longer life, lower decline asset base remained on course as we delivered cost effective production volumes from Pelican Lake and brought Kirby South onstream. At Horizon Oil Sands, we commissioned the Phase 2A coker expansion ahead of schedule and below budget, resulting in increased utilization and name plate capacity. In 2015, we will leverage these execution synergies at Horizon, by reducing the scope of our planned 2015 turnaround, thereby increasing our 2015 annual Horizon production target by approximately 10,000 bbl/d. The majority of the original turnaround scope planned for 2015 will now be executed in May 2016 coincidental with additional Horizon project tie-in activity.

Although we were faced with new crude oil pricing challenges in the fourth quarter of 2014, we have been able to adapt quickly to the changing conditions through our nimble, flexible capital allocation. With a disciplined business approach and a focus on operating and capital costs, our proven strategy allows us to withstand the current commodity price challenges 2015 is bringing.”

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “Strong cost management and prudent financial discipline continue to remain our focus given the volatility in commodity prices. Our proven track record of exercising capital flexibility and taking advantage of opportunities, such as the reduction in scope of the 2015 Horizon turnaround, facilitate the continued delivery of our defined plan and returning cash to shareholders, while maintaining a strong balance sheet and liquidity position. As a result of the Board of Directors’ confidence in the Company’s continued strength and successful execution of its proven and effective strategy, the quarterly cash dividend on common shares has once again been increased to $0.23 per share, the fifteenth straight year of increases in the Company’s dividend. Available year end liquidity of $2.6 billion was subsequently bolstered in the first quarter of 2015 by the Company entering into a new $1.5 billion 3 year drawn bank credit facility, further supporting our financial stability and resilience. Beyond today’s $150 million Horizon turnaround capital reduction, we retain additional optionality in our capital program as we move through 2015 and in future years, facilitating value creation for our shareholders irrespective of commodity price cycles.”

QUARTERLY AND ANNUAL HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended Dec 31 2014	Sep 30 2014	Dec 31 2013	Year Ended Dec 31 2014	Dec 31 2013
Net earnings	**$ 1,198**	$ 1,039	$ 413	**$ 3,929**	$ 2,270
Per common share – basic	**$ 1.10**	$ 0.95	$ 0.38	**$ 3.60**	$ 2.08
– diluted	**$ 1.09**	$ 0.94	$ 0.38	**$ 3.58**	$ 2.08
Adjusted net earnings from operations (1)	**$ 756**	$ 984	$ 563	**$ 3,811**	$ 2,435
Per common share – basic	**$ 0.69**	$ 0.90	$ 0.52	**$ 3.49**	$ 2.24
– diluted	**$ 0.69**	$ 0.89	$ 0.52	**$ 3.47**	$ 2.23
Cash flow from operations (2)	**$ 2,368**	$ 2,440	$ 1,782	**$ 9,587**	$ 7,477
Per common share – basic	**$ 2.17**	$ 2.23	$ 1.64	**$ 8.78**	$ 6.87
– diluted	**$ 2.16**	$ 2.21	$ 1.64	**$ 8.74**	$ 6.86
Capital expenditures, net of dispositions	**$ 2,220**	$ 2,175	$ 2,091	**$ 11,744**	$ 7,274
Daily production, before royalties					
Natural gas (MMcf/d)	**1,733**	1,674	1,195	**1,555**	1,158
Crude oil and NGLs (bbl/d)	**572,040**	518,007	478,038	**531,194**	478,240
Equivalent production (BOE/d) (3)	**860,920**	796,931	677,242	**790,410**	671,162

(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 Overview

- Canadian Natural realized cash flow from operations in 2014 of approximately $9.6 billion. This is a 28% increase in cash flow compared to approximately $7.5 billion in 2013. The increase in cash flow was primarily due to higher overall crude oil and NGLs, natural gas and synthetic crude oil ("SCO") sales volumes in North America, higher crude oil and NGLs and natural gas netbacks in North America, higher realized risk management gains and the impact of a weaker Canadian dollar relative to the US dollar.
- Net earnings increased to $3.9 billion in 2014 compared to $2.3 billion in 2013. Adjusted net earnings from operations increased to $3.8 billion in 2014 compared to $2.4 billion in 2013. Changes in adjusted net earnings reflect the changes in cash flow from operations.
- Total overall production for the year averaged a record level of approximately 790,400 BOE/d, representing an increase of 18% from 2013 levels.
- Total crude oil and NGL production for the year averaged a record level of approximately 531,200 bbl/d, an increase of 11% from 2013 levels. Crude oil production was driven by the following:
  - 31% annual increase in North America light crude oil and NGL production as a result of the successful integration of production volumes acquired in the first half of 2014 and a successful drilling program,
  - 17% annual increase in Pelican Lake production due to excellent reservoir and polymer flood operating performance,
  - 12% annual increase in thermal in situ production as Kirby South volumes advanced toward 40,000 bbl/d,

- 10% annual increase in Horizon Oil Sands Mining ("Horizon") production which included 25 days of planned downtime in Q3/14 used to complete the Coker plant expansion. Solid production volumes resulted from a continued focus on safe, steady and reliable operations targeting higher utilization rates; and,

- 5% annual increase in primary heavy crude oil production as a result of a successful drilling program.

▪ Total natural gas production for the year averaged 1,555 MMcf/d and increased by 34% from 2013 levels due to the successful integration of volumes acquired in the first half of the year, the impact of full year production volumes from the Septimus expansion, and a concentrated liquids-rich natural gas drilling program.

▪ Canadian Natural ended 2014 with a strong balance sheet with debt to book capitalization of 33% and debt to EBITDA of 1.3x at December 31, 2014.

▪ Canadian Natural maintains significant financial stability and liquidity represented in part by bank credit facilities. As at December 31, 2014, the Company had in place bank credit facilities of $5,627 million, of which $2,643 million, net of commercial paper issuances of $580 million, was available.

▪ Subsequent to December 31, 2014, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018. Additionally, the Company extended its existing $1,000 million non-revolving term credit facility to January 2017. The additional access to these credit facilities allows the Company to maintain its strong liquidity position.

▪ Canadian Natural has increased its quarterly cash dividend on common shares to C$0.23 per share from C$0.225 per share payable on April 1, 2015.

▪ Canadian Natural's crude oil, SCO, bitumen, natural gas and NGL reserves were evaluated and reviewed by Independent Qualified Reserves Evaluators. The following highlights are based on the Company's reserves using forecast prices and costs as at December 31, 2014 (all reserve values are Company Gross unless stated otherwise):

  - Canadian Natural total proved crude oil, SCO, bitumen and NGL reserves increased 2% to 4.51 billion barrels. Proved natural gas reserves increased 39% to 6.00 Tcf. Total proved reserves increased 7% to 5.51 billion BOE, resulting in a reserve life index of 19.0 years.

  - Canadian Natural total proved reserves increased by 662 million BOE through additions and revisions, resulting in a proved reserve replacement ratio of 230%.

  - Canadian Natural total proved plus probable crude oil, SCO, bitumen and NGL reserves increased 8% to 7.54 billion barrels. Proved plus probable natural gas reserves increased 33% to 8.14 Tcf. Total proved plus probable reserves increased 11% to 8.89 billion BOE resulting in a reserve life index of 30.6 years.

  - Canadian Natural total proved plus probable reserves increased by 1,188 million BOE through additions and revisions, resulting in a proved plus probable reserve replacement ratio of 413%.

  - Canadian Natural total net exploration and production reserve replacement expenditures totaled approximately $8.18 billion in 2014, including acquisitions and excluding Horizon. Horizon project capital (including capitalized interest, share-based compensation and other) totaled approximately $2.73 billion and sustaining and turnaround capital totaled approximately $380 million.

Fourth Quarter Overview

▪ Total crude oil and NGL production was approximately 572,000 bbl/d for Q4/14, an increase of 20% from Q4/13 levels, resulting largely from increased crude oil and NGL production volumes across all business divisions. Q4/14 production volumes increased by 10% from the previous quarter as a result of added production volumes from the successful completion of the coker expansion tie-in in Q3/14 at Horizon.

▪ Total natural gas production was 1,733 MMcf/d in Q4/14, an increase of 45% and 4% from Q4/13 and Q3/14 levels respectively. Increases in production levels, from the same quarter in the previous year, were largely due to acquisitions completed in the first half of the year and the concentrated liquids-rich Montney natural gas drilling program at Septimus. The increase from Q3/14 levels was primarily a result of minor property acquisitions completed in Q4/14 as well as growth from the current drilling program.

- Canadian Natural generated cash flow from operations of approximately $2.4 billion in Q4/14 compared to approximately $1.8 billion in Q4/13 and $2.4 billion in Q3/14. The increase in Q4/14 levels from Q4/13 levels reflect higher sales volumes in North America from crude oil and NGLs, natural gas and SCO, higher realized risk management gains and the impact of a weaker Canadian dollar relative to the US dollar partially offset by lower crude oil sales volumes in the Offshore Africa segment, lower crude oil and NGLs netbacks in the North America, North Sea and Offshore Africa segments and lower SCO prices. The slight reduction in cash flow from Q3/14 levels reflects lower crude oil and NGL netbacks in the North America, North Sea and Offshore Africa segments, lower realized SCO prices and lower crude oil sales volumes in Offshore Africa, partially offset by higher SCO sales volumes from Horizon, higher realized risk management gains and the impact of a weaker Canadian dollar as compared to the US dollar.
- Net earnings from operations for Q4/14 were $1,198 million, compared to net earnings of $413 million in Q4/13 and $1,039 million in Q3/14. Adjusted net earnings from operations for Q4/14 were $756 million, compared to adjusted net earnings of $563 million in Q4/13 and $984 million in Q3/14. Changes in adjusted net earnings reflect the changes in cash flow.

Operational and Financial Highlights

- In 2014 the Company achieved record annual aggregate production volumes for all North America Exploration and Production crude oil and NGL assets, which increased 14% from 2013 levels.
  - North America light crude oil and NGLs achieved record annual production volumes of approximately 89,600 bbl/d. Production increased 31% from 2013 levels, largely as a result of the successful integration of light crude oil and NGL production volumes acquired in the first half of 2014, as well as a successful drilling program.
  - Canadian Natural’s primary heavy crude oil continued to provide strong netbacks and provides one of the highest returns on capital in the Company’s portfolio of diverse and balanced assets. Primary heavy crude oil operations achieved record annual production of approximately 143,400 bbl/d, representing a 5% increase from 2013 levels.
  - Pelican Lake operations achieved record annual heavy crude oil production volumes of approximately 50,100 bbl/d, a 17% increase from 2013 levels. Canadian Natural continues to achieve success in developing, implementing and optimizing the leading edge polymer flood technology at Pelican Lake.
    - In Q4/14, Pelican Lake’s operating costs were $7.82/bbl contributing to overall annual operating costs for 2014 of $8.52/bbl, representing a 20% decrease in operating costs from 2013 levels. Industry leading Pelican Lake operating costs drive high netbacks and significant free cash flow generation.
- During 2014 thermal in situ annual production volumes averaged approximately 107,800 bbl/d, a 12% increase from 2013 volumes primarily as a result of added volumes from Kirby South.
  - In September 2014, Canadian Natural received approval from the Alberta Energy Regulator (“AER”) to implement a low pressure steamflood at Primrose East Area 1. The steamflood commenced and production is ramping up as expected.
  - Subsequent to December 31, 2014, the Company received approval from the AER to implement low pressure cyclic steam stimulation (“CSS”) at Primrose East Area 2.
  - At Kirby South, Q4/14 production averaged approximately 22,200 bbl/d and production volumes continue to ramp up to the targeted 40,000 bbl/d of design capacity with the reservoir performing as expected.
- Horizon achieved record annual average production of approximately 110,600 bbl/d of SCO, an increase of 10% from 2013 levels. After successfully completing the Coker plant expansion in Q3/14, 8 months ahead of the original schedule, utilization rates at Horizon were 96% in Q4/14 as production volumes reached a quarterly record level of approximately 128,100 bbl/d of SCO.
  - Through the completion of Phase 2A, additional coker capacity and equipment were added, increasing the plant name plate capacity to 133,000 bbl/d. New equipment performance combined with an optimized mining strategy have increased the stability of the extraction and upgrading processes, resulting in a further increase to plant name plate capacity to 137,000 bbl/d. As a result, the last three months (December 2014, January 2015 and February 2015) production volumes were approximately 136,000 bbl/d, 135,600 bbl/d and 136,600 bbl/d respectively, at Horizon, representing a utilization level of 99%.

- The addition of facility redundancy through the completion of Phase 2A, along with a more effective mining strategy, will place less maintenance stress on the downstream equipment and has increased overall performance of the plant. As a result of this increased performance and the strong execution of the Phase 2B expansion, the 35 day maintenance turnaround originally planned for the latter half of 2015 has been reduced in scope for this year to six days, and remaining work is now targeted for May 2016. In addition, due to continued strong construction performance on the Horizon expansion, the tie-in work for the Phase 2B expansion is now targeted to be completed during this 2016 maintenance turnaround, which will enable targeted production of Phase 2B to incrementally increase earlier than previously expected. Production volumes after the turnaround are targeted to increase by 4,000 bbl/d in Q3/16 and 10,000 bbl/d in Q4/16, above the original ramp up of production planned. Phase 2B is targeted to add 45,000 bbl/d of productive capacity once fully commissioned in late 2016.
- The now planned 2015 six day turnaround is targeted for this fall to ensure continued safe, steady and reliable production at Horizon. As a result of a shorter planned 2015 turnaround period, additional production volumes of 10,000 bbl/d are now targeted for 2015 and annual production guidance has increased to 121,000 bbl/d to 131,000 bbl/d.
- Adjusted operating costs at Horizon averaged $37.18/bbl in 2014, representing a decrease of 8% from levels of $40.57/bbl in 2013. In Q4/14, adjusted operating costs averaged $34.34/bbl, representing a decrease of 12% and 8% from Q4/13 and Q3/14 levels respectively. Decreases in adjusted operating costs reflect improvement in safe, steady and reliable operations, the impact of cost reduction initiatives across the site, the production and internal use of mine diesel, and higher production volumes on a relatively fixed cost structure. Due to these improvements at Horizon, adjusted cash production costs are targeted to further decrease in 2015 and average between $32.00/bbl to $35.00/bbl this year.

▪ Total natural gas production reached 1,555 MMcf/d on an annual basis in 2014, an increase of 34% from 2013 levels. The increase from 2013 levels resulted from the successful integration of acquired properties in North America, the impact of full year production volumes from the Septimus expansion, and a concentrated liquids-rich natural gas drilling program.

▪ Western Canadian Select (“WCS”) differential to West Texas Intermediate (“WTI”) averaged US$19.41/bbl or 21% in 2014 compared to US$25.11/bbl or 26% in 2013. A narrower differential resulted from additional heavy crude oil demand in the U.S. Midwest and increased takeaway capacity to the U.S. Gulf Coast.

▪ Canadian Natural is continuing its review of its royalty lands and royalty revenue portfolio and the best options to maximize shareholder value. Options for a final strategy as it relates to its fee title and royalty lands are as follows:

- Divestiture of the portfolio assets,
- Spin-off of the portfolio assets (IPO), or
- Retention of the portfolio assets in their current state.

  – The development of leased acreage is ongoing and lease requests on undeveloped acreage continue to be evaluated. Production on the royalty lands has increased 10% from Q2/14 levels to Q3/14 levels. Drilling activity has been strong on the Company’s royalty lands with 268 wells drilled in Q3/14 and Q4/14, of which 219 wells were drilled by third party and 49 wells were drilled by Canadian Natural.

▪ For the year ended December 31, 2014, the Company purchased for cancellation, under its Normal Course Issuer Bid, 10,095,000 common shares at a weighted average price of $44.85 per common share.

▪ Canadian Natural has increased its quarterly cash dividend on common shares to C$0.23 per share from C$0.225 per share payable on April 1, 2015.

2015 Capital and Operating Budget Updates

▪ Capital guidance for 2015 has been reduced by $150 million as a result of the reduction in scope of the originally planned 2015 Horizon maintenance turnaround from 35 days to 6 days. This is a result of the increased operating performance and the strong execution of the Phase 2B expansion. Tie-in work for the Phase 2B expansion will be completed during the maintenance turnaround, now targeted for May 2016.

▪ As a result of the focus on cost control in the current commodity price environment, members of Canadian Natural’s Management Committee have agreed to a 10% salary reduction, effective March 1, 2015. Concurrently, the Board of Directors has also agreed to reduce their annual Board cash retainer by 10%.

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.

Drilling activity

	Year Ended Dec 31			
	2014		2013	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**1,112**	**1,023**	1,180	1,117
Natural gas	**100**	**75**	60	44
Dry	**21**	**19**	31	30
Subtotal	**1,233**	**1,117**	1,271	1,191
Stratigraphic test / service wells	**444**	**437**	384	384
Total	**1,677**	**1,554**	1,655	1,575
Success rate (excluding stratigraphic test / service wells)		**98%**		97%

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Crude oil and NGLs production (bbl/d)	**291,002**	288,858	254,162	**283,012**	247,196
Net wells targeting crude oil	**332**	275	299	**1,021**	1,000
Net successful wells drilled	**324**	270	289	**1,003**	974
Success rate	**98%**	98%	97%	**98%**	97%

- North America crude oil and NGLs achieved record quarterly production of approximately 291,000 bbl/d in Q4/14, an increase of 14% from Q4/13 levels and a slight increase from Q3/14 levels.
- In Q4/14, primary heavy crude oil operations achieved record quarterly production of approximately 144,700 bbl/d. Primary heavy crude oil production increased 7% from Q4/13 levels and achieved a slight increase from Q3/14 levels. The Company’s large undeveloped land base, effective and efficient drilling program and vast inventory of over 8,000 potential well locations enables Canadian Natural to remain the industry leading primary heavy crude oil producer. Canadian Natural continued with its large and cost efficient drilling program, drilling 896 net primary heavy crude oil wells in 2014.
- Canadian Natural’s primary heavy crude oil assets provide strong netbacks and are amongst the highest return on capital in the Company’s North America portfolio of diverse and balanced assets.

- Pelican Lake operations achieved record annual heavy crude oil production volumes of approximately 50,100 bbl/d, a 17% increase from 2013 levels. Canadian Natural continues to achieve success in developing, implementing and optimizing the leading edge polymer flood technology at Pelican Lake.
  - In Q4/14, Pelican Lake's operating costs were $7.82/bbl contributing to overall annual operating costs for 2014 of $8.52/bbl, representing a 20% decrease in operating costs from 2013 levels. Industry leading Pelican Lake operating costs drive high netbacks and significant free cash flow generation.
- North America light crude oil and NGLs achieved record quarterly production of approximately 95,600 bbl/d in Q4/14. Production increased 30% and 2% from Q4/13 levels and Q3/14 levels respectively, largely as a result of the successful integration of light crude oil and NGL production volumes acquired in 2014, as well as a successful drilling program.

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Bitumen production (bbl/d)	**118,974**	115,256	78,069	**107,802**	96,503
Net wells targeting bitumen	–	1	38	**15**	145
Net successful wells drilled	–	1	35	**15**	142
Success rate	–	100%	92%	**100%**	98%

- During 2014 thermal in situ annual production volumes averaged approximately 107,800 bbl/d, a 12% increase from 2013 volumes primarily as a result of added volumes from Kirby South.
- Q4/14 thermal in situ production volumes were approximately 119,000 bbl/d, representing an increase of 52% and 3% from Q4/13 and Q3/14 levels respectively. The increase in Q4/14 from Q4/13 levels primarily reflects the recommencement of steaming at Primrose East Area 1 and the addition of increased Kirby South production volumes.
- Primrose production volumes remained solid in Q4/14 as additional steaming approvals were received allowing execution of the Company's development plans:
  - In September 2014, Canadian Natural received approval from the AER to implement a low pressure steamflood at Primrose East Area 1. The steamflood commenced and production is ramping up as expected.
  - Primrose South received approval for additional CSS on four pads in September 2014; production is targeted to ramp up in 2015.
  - Subsequent to December 31, 2014, the Company received approval from the AER to implement low pressure CSS at Primrose East Area 2.
- At Kirby South, 2014 annual production averaged approximately 15,200 bbl/d as Q4/14 production volumes increased to an average of approximately 22,200 bbl/d. Kirby South continues to ramp to the targeted 40,000 bbl/d of design capacity with the reservoir performing as expected. Previously announced mechanical issues, which were resolved in Q3/14, limited the amount of steam entering the reservoir. The restriction in steam capacity deferred the timing to achieve full production capacity. Reservoir performance, as measured by steam to oil ratio ("SOR") continues to be strong with January 2015 and February 2015 SORs of 2.42 and 2.40 respectively for wells on Steam Assisted Gravity Drainage ("SAGD"), and total production levels of approximately 23,400 bbl/d and 25,300 bbl/d respectively.

Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Natural gas production (MMcf/d)	**1,705**	1,644	1,165	**1,527**	1,130
Net wells targeting natural gas	**16**	22	11	**76**	45
Net successful wells drilled	**16**	21	11	**75**	44
Success rate	**100%**	95%	100%	**99%**	98%

- North America natural gas production averaged 1,705 MMcf/d for Q4/14, an increase of 46% and 4% from Q4/13 and Q3/14 levels respectively. The increase from Q4/13 levels resulted from additional production volumes acquired in the first half of the year and minor property acquisitions completed in Q4/14. The increase from Q3/14 levels was due to a concentrated liquids-rich natural gas drilling program and the successful integration of the previously mentioned acquired volumes.
- Concurrent with the successful integration of the acquired volumes and the continued focus on effective and efficient operations, the Company reduced operating costs related to these assets by approximately $86 million during 2014. Q4/14 operating costs were $1.34/Mcf, comparable to Q4/13 and Q3/14.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Crude oil production (bbl/d)					
North Sea	**21,927**	18,197	20,155	**17,380**	18,334
Offshore Africa	**12,047**	13,684	13,379	**12,429**	15,923
Natural gas production (MMcf/d)					
North Sea	**10**	7	7	**7**	4
Offshore Africa	**18**	23	23	**21**	24
Net wells targeting crude oil	**1.0**	1.8	–	**4.5**	1.0
Net successful wells drilled	**1.0**	1.8	–	**4.5**	1.0
Success rate	**100%**	100%	–	**100%**	100%

- International crude oil production averaged approximately 34,000 bbl/d during Q4/14, comparable to Q4/13 levels and a 7% increase from Q3/14 levels. The increase in production over Q3/14 levels was primarily due to the reinstatement of the Banff/Kyle FPSO in July 2014. Production had been suspended for this FPSO since 2011 after the infrastructure suffered storm damage.
- Canadian Natural has contracted a drilling rig to undertake a 10 well (5.9 net) infill development drilling program targeted to add 5,900 BOE/d of net production at the Espoir field, offshore Côte d'Ivoire. Drilling commenced in January 2015 and first oil is targeted at the end of Q1/15.
- The Company has contracted a drilling rig to undertake a 6 well (3.5 net) infill development drilling program targeted to add 11,000 BOE/d of net production at the Baobab field, offshore Côte d'Ivoire. Drilling has commenced and first oil is targeted in Q2/15.
- In Q2/14, an exploratory well was drilled on Block CI-514, in which the Company has a 36% working interest. The well demonstrated the presence of a working petroleum system. A second well is targeted to be drilled in the first half of 2015 to evaluate the up-dip potential of the initial well.

- Canadian Natural has a 50% interest in the Block 11B/12B Exploration Right located in the Outeniqua Basin, approximately 175 kilometers off the southern coast of South Africa. In Q3/14, the operator, Total E&P South Africa BV, a wholly owned subsidiary of Total SA, commenced drilling the first exploratory well. In Q4/14, the exploration well was suspended due to mechanical issues with marine equipment on the drilling rig. The rig safely left the well location and, as the available drilling window has ended, it has been demobilized by the operator. The South African authorities have formally confirmed that the well drilled satisfies the work obligation for the initial period of the Block 11B/12B Exploration Right. The operator is reviewing the course of action to re-enter the well, and has indicated drilling operations are unlikely to resume in the area before 2016.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Synthetic crude oil production (bbl/d) (1)	**128,090**	82,012	112,273	**110,571**	100,284

(1) The Company has commenced production of diesel for internal use at Horizon. Fourth quarter 2014 SCO production before royalties excludes 1,288 bbl/d of SCO consumed internally as diesel (third quarter 2014 – 875 bbl/d; year ended December 31, 2014 – 545 bbl/d).

- Horizon achieved record annual average production of approximately 110,600 bbl/d of SCO, an increase of 10% from 2013 levels. After successfully completing the Coker plant expansion in Q3/14, 8 months ahead of the original schedule, utilization rates at Horizon were 96% in Q4/14 as production volumes reached a quarterly record level of approximately 128,100 bbl/d of SCO.

- Through the completion of Phase 2A, additional coker capacity and equipment were added, increasing the plant name plate capacity to 133,000 bbl/d. New equipment performance combined with an optimized mining strategy have increased the stability of the extraction and upgrading processes, resulting in a further increase to plant name plate capacity to 137,000 bbl/d. As a result, the last three months (December 2014, January 2015 and February 2015) production volumes were approximately 136,000 bbl/d, 135,600 bbl/d and 136,600 bbl/d respectively, at Horizon, representing a utilization level of 99%.

- The addition of facility redundancy through the completion of Phase 2A, along with a more effective mining strategy, will place less maintenance stress on the downstream equipment and has increased overall performance of the plant. As a result of this increased performance and the strong execution of the Phase 2B expansion, the 35 day maintenance turnaround originally planned for the latter half of 2015 has been reduced in scope for this year to six days, and remaining work is now targeted for May 2016. In addition, due to continued strong construction performance on the Horizon expansion, the tie-in work for the Phase 2B expansion is now targeted to be completed during this 2016 maintenance turnaround, which will enable targeted production of Phase 2B to incrementally increase earlier than previously expected. Production volumes after the turnaround are targeted to increase by 4,000 bbl/d in Q3/16 and 10,000 bbl/d in Q4/16, above the original ramp up of production planned. Phase 2B is targeted to add 45,000 bbl/d of productive capacity once fully commissioned in late 2016.
- The now planned 2015 six day turnaround is targeted for this fall to ensure continued safe, steady and reliable production at Horizon. As a result of a shorter planned 2015 turnaround period, additional production volumes of 10,000 bbl/d are now targeted for 2015 and annual production guidance has increased to 121,000 bbl/d to 131,000 bbl/d.

- Adjusted operating costs at Horizon averaged $37.18/bbl in 2014, representing a decrease of 8% from levels of $40.57/bbl in 2013. In Q4/14, adjusted operating costs averaged $34.34/bbl, representing a decrease of 12% and 8% from Q4/13 and Q3/14 levels respectively. Decreases in adjusted operating costs reflect improvement in safe, steady and reliable operations, the impact of cost reduction initiatives across the site, the production and internal use of mine diesel, and higher production volumes on a relatively fixed cost structure. Due to these improvements at Horizon, adjusted cash production costs are targeted to further decrease in 2015 and average between $32.00/bbl to $35.00/bbl this year.

- Canadian Natural continues to deliver on its strategy to transition to a longer life, low decline asset base while providing significant and growing free cash flow. Canadian Natural's staged expansion of Horizon to 250,000 bbl/d of SCO production capacity continues to progress on track and within cost estimates. Canadian Natural has committed to approximately 72% of the Engineering, Procurement and Construction contracts with over 70% of the construction contracts awarded to date, 85% being lump sum, ensuring greater cost certainty and efficiency.
- Overall Horizon Phase 2/3 expansion is 56% physically complete as at Q4/14:

- Reliability – Tranche 2 is 100% physically complete. Completion occurred in 2014 resulting in increased performance and overall production reliability. This phase contributed approximately 5% increase in production levels from Phase 1 production levels.
- Directive 74 includes technological investment and research into tailings management. This project remains on track and is 51% physically complete.
- Phase 2A is a coker expansion that 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 accelerated the tie-in to August 2014. The expanded Coker Unit is now fully operational and the project was completed on time and below budget. Horizon SCO production levels increased by approximately 12,000 bbl/d with the completion of the coker tie-in.
- Phase 2B is 49% physically complete. This phase expands the capacity of major components such as gas/oil hydrotreatment, froth treatment and the hydrogen plant. As a result of strong project execution, certain components of this project will be tied-in during the May 2016 turnaround. Full commissioning of the Phase 2B equipment will be completed as planned in late 2016, adding 45,000 bbl/d of production capacity.
- Phase 3 is on track and on schedule. This phase is 44% physically complete, and includes the addition of extraction trains. This phase is targeted to increase production capacity by 80,000 bbl/d in late 2017 and will result in additional reliability, redundancy and significant operating cost savings for the Horizon project.

ROYALTIES

Based on the analysis completed to date, Canadian Natural reports the following information for quarterly royalty volumes, which are based on the Company's current estimate of revenue and volumes attributable to Q3/14:

Royalty Production Volumes Comparison (1)

	Q3/14	**Q2/14**
Natural gas (MMcf/d)	23.6	21.0
Crude oil (bbl/d)	4,047	3,701
NGLs (bbl/d)	472	463
Total (BOE/d)	**8,448**	**7,665**

Royalty Production Volumes (1)

	Royalty volumes for Q3/14 attributable to		
	Third Party	**Canadian Natural** (2)	**Total**
Natural gas (MMcf/d)	19.9	3.7	23.6
Crude oil (bbl/d)	3,329	718	4,047
NGLs (bbl/d)	438	34	472
Total (BOE/d)	**7,083**	**1,365**	**8,448**

Royalty Revenue by Product (1)

	Royalty revenue for Q3/14 attributable to		
($ millions)	**Third Party**	**Canadian Natural** (2)	**Total**
Natural gas	$ 7	$ 2	$ 9
Crude oil	$ 27	$ 5	$ 32
NGLs	$ 2	$ –	$ 2
Other revenue (3)	$ 4	$ –	$ 4
Total	**$ 40**	**$ 7**	**$ 47**

Revenue by Royalty Classification [1]

($ millions)	Royalty revenue for Q3/14 attributable to Third Party	Canadian Natural [2]	Total
Fee title	$ 23	$ 6	$ 29
Gross overriding royalty [4]	$ 13	$ 1	$ 14
Other revenue [3]	$ 4	$ –	$ 4
Total	**$ 40**	**$ 7**	**$ 47**

Royalty Realized Pricing [1]

	Q3/14
Natural gas ($/Mcf)	$ 3.94
Crude oil ($/bbl)	$ 86.82
NGLs ($/bbl)	$ 54.24
Total ($/BOE)	**$ 60.09**

Royalty Acreage

(gross acres, millions)	Leased to Third Party and Unleased	Canadian Natural [2]	Total
Fee title [5]	3.14	0.22	3.36
Gross overriding royalty [4]	1.90	1.62	3.52
Total	**5.04**	**1.84**	**6.88**

(1) Based on the Company's current estimate of revenue and volumes attributable to the noted period.

(2) Indicates Canadian Natural is both the Lessor and Lessee, thereby incurring intercompany royalties; in addition there are certain Canadian Natural fee title lands where the Company has production where no royalty burden has been recognized in this table.

(3) Includes sulphur revenue, bonus payments, lease rentals and compliance revenue.

(4) Includes Net Profit Interests and other royalties.

(5) Includes Fee title and Freehold.

- The development of leased acreage is ongoing and lease requests on undeveloped acreage continue to be evaluated. Production on the royalty lands has increased 10% from Q2/14 levels to Q3/14 levels. Drilling activity has been strong on the Company's royalty lands with 268 wells drilled in Q3/14 and Q4/14, of which 219 wells were drilled by third party and 49 wells were drilled by Canadian Natural.
- The Company continues to focus on lease compliance, well commitments, offset drilling obligations and compensatory royalties payable.
- Royalty production volumes highlighted above are not reported in Canadian Natural's quarterly production volumes. Third party royalty revenues are included in reported Product Sales in the Company's consolidated statement of earnings.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 73.12**	$ 97.21	$ 97.50	**$ 92.92**	$ 98.00
WCS blend differential from WTI (%) (2)	**20%**	21%	33%	**21%**	26%
SCO price (US$/bbl)	**$ 71.01**	$ 94.31	$ 88.37	**$ 91.35**	$ 98.18
Condensate benchmark pricing (US$/bbl)	**$ 70.54**	$ 93.49	$ 94.30	**$ 92.84**	$ 101.67
Average realized pricing before risk management (C$/bbl) (3)	**$ 62.80**	$ 79.99	$ 69.38	**$ 77.04**	$ 73.81
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 3.80**	$ 4.00	$ 2.99	**$ 4.19**	$ 3.00
Average realized pricing before risk management (C$/Mcf)	**$ 4.32**	$ 4.54	$ 3.62	**$ 4.83**	$ 3.58

(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$/bbl)**	**WCS Blend Differential from WTI (%)**	**WCS Blend Differential from WTI ($)**	**SCO Differential from WTI (US$/bbl)**	**Dated Brent Differential from WTI (US$/bbl)**	**Condensate Differential from WTI (US$/bbl)**
2014						
October	$ 84.34	16%	$ (13.74)	$ (0.48)	$ 2.93	$ (0.09)
November	$ 75.81	17%	$ (12.94)	$ (0.45)	$ 2.63	$ (2.13)
December	$ 59.29	27%	$ (16.05)	$ (5.34)	$ 3.04	$ (5.51)
2015						
January	$ 47.33	36%	$ (16.90)	$ (3.16)	$ 0.74	$ (4.89)
February*	$ 50.72	28%	$ (14.20)	$ (3.43)	$ 7.21	$ (4.24)
March*	$ 50.52	26%	$ (13.09)	$ (3.33)	$ 11.59	$ 0.09

**Based on current indicative pricing as at March 2, 2015.*

- Volatility in supply and demand factors and geopolitical events continued to affect WTI and Brent pricing. During Q4/14, an oversupply in the world market contributed to a significant decrease in crude oil benchmark pricing. The Organization of the Petroleum Exporting Countries' ("OPEC") decision in November 2014 to not reduce crude oil production to offset the excess world supply continues to put downward pressure on benchmark pricing. The Brent differential from WTI narrowed during the fourth quarter of 2014 compared to the fourth quarter of 2013 due to continued debottlenecking of logistical constraints from Cushing to the US Gulf Coast in the first half of 2014.
- The WCS differential to WTI averaged US$19.41/bbl or 21% in 2014 compared to US$25.11/bbl or 26% in 2013. A narrower differential resulted from additional heavy crude oil demand in the U.S. Midwest and increased takeaway capacity to the U.S. Gulf Coast. Throughout 2015, seasonal demand fluctuations, changes in transportation logistics, and refinery utilization and shutdowns are expected to contribute to fluctuation in the WCS heavy oil differential.

- Canadian Natural contributed approximately 167,000 bbl/d of its heavy crude oil stream to the WCS blend in 2014. The Company remains the largest contributor to the WCS blend, accounting for 56% of the total blend in Q4/14.
- SCO pricing during Q4/14 decreased 20% and 25% from Q4/13 levels and Q3/14 levels respectively, primarily due to a decrease in benchmark pricing.
- During Q4/14, natural gas prices increased from Q4/13 due to the drawdown of natural gas storage inventories as a result of colder than normal winter temperatures in 2014. Natural gas prices decreased in Q4/14 from Q3/14 due to the strong growth in US natural gas production. The growth of US natural gas production resulted in inventories returning to normal industry levels at the end of 2014, leading to downward pressure on natural gas prices.

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. For project updates, please refer to: www.nwrpartnership.com/brief-updates.

FINANCIAL REVIEW

The Company continues to implement proven strategies and its disciplined approach to capital allocation. As a result, the financial position of Canadian Natural remains strong. Canadian Natural's cash flow generation, credit facilities, US commercial paper program, diverse asset base and related flexible 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 approximately 790,400 BOE/d for 2014 with approximately 98% of production located in G8 countries.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 33% and debt to EBITDA of 1.3x at December 31, 2014.
- Canadian Natural maintains significant financial stability and liquidity represented in part by bank credit facilities. As at December 31, 2014, the Company had in place bank credit facilities of $5,627 million, of which $2,643 million, net of commercial paper issuances of $580 million, was available.
- Subsequent to December 31, 2014, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018. Additionally, the Company extended its existing $1,000 million non-revolving term credit facility to January 2017. The additional access to these credit facilities allows the Company to maintain its strong liquidity position.
- On November 12, 2014, Canadian Natural priced US$600 million principal amount of 1.75% unsecured notes due January 15, 2018 sold at a price of 99.921% per note to yield 1.776% to maturity, and US$600 million principal amount of 3.90% unsecured notes due February 1, 2025 sold at a price of 99.871% per note to yield 3.916% to maturity.
- The Company's commodity hedging program is utilized, as required, to protect investment returns, support ongoing balance sheet strength and the 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, 2014, the Company purchased for cancellation 10,095,000 common shares at a weighted average price of $44.85 per common share.
- Canadian Natural has increased its quarterly cash dividend on common shares to C$0.23 per share from C$0.225 per share payable on April 1, 2015.
- The Company has a strong balance sheet and cash flow generation which enables it to weather volatility in commodity prices. Additionally, Canadian Natural retains significant capital expenditure program flexibility to proactively adapt to changing market conditions.

OUTLOOK

The Company forecasts 2015 production levels before royalties to average between 562,000 and 602,000 bbl/d of crude oil and NGLs and between 1,730 and 1,770 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, 2014 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. All reserve values are Company Gross unless stated otherwise.

Corporate Total

- Proved crude oil, SCO, bitumen and NGL reserves increased 2% to 4.51 billion barrels. Proved natural gas reserves increased 39% to 6.00 Tcf. Total proved reserves increased 7% to 5.51 billion BOE.
- Proved plus probable crude oil, SCO, bitumen and NGL reserves increased 8% to 7.54 billion barrels. Proved plus probable natural gas reserves increased 33% to 8.14 Tcf. Total proved plus probable reserves increased 11% to 8.89 billion BOE.
- Proved reserve additions and revisions, including acquisitions, were 282 million barrels of crude oil, SCO, bitumen and NGL and 2,264 billion cubic feet of natural gas. The total proved BOE reserve replacement ratio was 230%. The total proved BOE reserve life index is 19.0 years.
- Proved plus probable reserve additions and revisions, including acquisitions, were 753 million barrels of crude oil, bitumen, SCO and NGL and 2,597 billion cubic feet of natural gas. The total proved plus probable BOE reserve replacement ratio was 413%. The total proved plus probable BOE reserve life index is 30.6 years.
- Proved undeveloped crude oil, SCO, bitumen and NGL reserves accounted for 27% of the corporate total proved reserves and proved undeveloped natural gas reserves accounted for 5% of the corporate total proved reserves.

North America Exploration and Production

- Proved crude oil, bitumen and NGL reserves increased 9% to 2.05 billion barrels. Proved natural gas reserves increased 41% to 5.87 Tcf. Total proved BOE increased 18% to 3.03 billion barrels.
- Proved plus probable crude oil, bitumen and NGL reserves increased 9% to 3.49 billion barrels. Proved plus probable natural gas reserves increased 35% to 7.93 Tcf. Total proved plus probable BOE increased 15% to 4.81 billion barrels.
- Proved reserve additions and revisions, including acquisitions, were 308 million barrels of crude oil, bitumen and NGL and 2,266 billion cubic feet of natural gas. The total proved BOE reserve replacement ratio is 292%. The total proved BOE reserve life index in 13.1 years.
- Proved plus probable reserve additions and revisions, including acquisitions, were 420 million barrels of crude oil, bitumen and NGL and 2,602 billion cubic feet of natural gas. The total proved plus probable BOE reserve replacement ratio was 363%. The total proved plus probable BOE reserve life index is 20.7 years.
- Proved undeveloped crude oil, bitumen and NGL reserves accounted for 36% of the North America total proved reserves and proved undeveloped natural gas reserves accounted for 9% of the North America total proved reserves.
- Thermal oil sands ("bitumen") proved reserves increased 5% to 1.22 billion barrels primarily due new proved undeveloped additions at Primrose and Wolf Lake. Proved reserve additions and revisions were 99 million barrels. Total proved plus probable bitumen reserves increased 7% to 2.31 billion barrels.

North America Oil Sands Mining and Upgrading

- Proved plus probable SCO reserves increased 9% to 3.59 billion barrels, primarily due to a revised mine plan allowing mining to Total Volume : Bitumen In Place ("TV:BIP") of 13 versus 12 in the original plan.

International Exploration and Production

- North Sea proved reserves decreased 9% to 218 million BOE. North Sea proved plus probable reserves decreased 5% to 327 million BOE.
- Offshore Africa proved reserves decreased 4% to 104 million BOE primarily due to production. Offshore Africa proved plus probable reserves decreased 3% to 165 million BOE.

Summary of Company Gross Reserves

As of December 31, 2014
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude 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	114	125	233	371	1,969	3,907	96	3,559
Developed Non-Producing	5	22	2	–	–	256	5	77
Undeveloped	26	82	39	846	189	1,706	87	1,553
Total Proved	145	229	274	1,217	2,158	5,869	188	5,189
Probable	58	88	121	1,095	1,435	2,057	70	3,210
Total Proved plus Probable	203	317	395	2,312	3,593	7,926	258	8,399
North Sea								
Proved								
Developed Producing	28					60		38
Developed Non-Producing	10					5		11
Undeveloped	166					18		169
Total Proved	204					83		218
Probable	104					31		109
Total Proved plus Probable	308					114		327
Offshore Africa								
Proved								
Developed Producing	24					32		29
Developed Non-Producing	–					–		–
Undeveloped	72					17		75
Total Proved	96					49		104
Probable	53					49		61
Total Proved plus Probable	149					98		165
Total Company								
Proved								
Developed Producing	166	125	233	371	1,969	3,999	96	3,626
Developed Non-Producing	15	22	2	–	–	261	5	88
Undeveloped	264	82	39	846	189	1,741	87	1,797
Total Proved	445	229	274	1,217	2,158	6,001	188	5,511
Probable	215	88	121	1,095	1,435	2,137	70	3,380
Total Proved plus Probable	660	317	395	2,312	3,593	8,138	258	8,891

Summary of Company Net Reserves

As of December 31, 2014
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude 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	99	105	176	281	1,609	3,436	71	2,913
Developed Non-Producing	4	18	1	–	–	215	4	63
Undeveloped	23	69	29	668	155	1,403	68	1,246
Total Proved	126	192	206	949	1,764	5,054	143	4,222
Probable	48	69	82	838	1,139	1,737	53	2,519
Total Proved plus Probable	174	261	288	1,787	2,903	6,791	196	6,741
North Sea								
Proved								
Developed Producing	28					60		38
Developed Non-Producing	10					5		11
Undeveloped	166					18		169
Total Proved	204					83		218
Probable	104					31		109
Total Proved plus Probable	308					114		327
Offshore Africa								
Proved								
Developed Producing	21					23		25
Developed Non-Producing	–					–		–
Undeveloped	57					13		59
Total Proved	78					36		84
Probable	41					32		46
Total Proved plus Probable	119					68		130
Total Company								
Proved								
Developed Producing	148	105	176	281	1,609	3,519	71	2,976
Developed Non-Producing	14	18	1	–	–	220	4	74
Undeveloped	246	69	29	668	155	1,434	68	1,474
Total Proved	408	192	206	949	1,764	5,173	143	4,524
Probable	193	69	82	838	1,139	1,800	53	2,674
Total Proved plus Probable	601	261	288	1,787	2,903	6,973	196	7,198

Reconciliation of Company Gross Reserves

As of December 31, 2014
Forecast Prices and Costs

PROVED

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	117	244	258	1,157	2,211	4,160	110	4,790
Discoveries	1	–	–	–	–	14	1	5
Extensions	7	29	–	91	–	121	5	152
Infill Drilling	3	12	–	–	–	562	32	141
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	31	–	–	–	–	1,407	34	300
Dispositions	(1)	–	–	–	–	(1)	–	(1)
Economic Factors	(1)	(1)	–	–	(4)	(52)	(1)	(16)
Technical Revisions	7	(3)	34	8	(9)	215	20	94
Production	(19)	(52)	(18)	(39)	(40)	(557)	(13)	(276)
December 31, 2014	**145**	**229**	**274**	**1,217**	**2,158**	**5,869**	**188**	**5,189**

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	224	91	239
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	1	–	1
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	(16)	(6)	(17)
Technical Revisions	1	1	2
Production	(6)	(3)	(7)
December 31, 2014	**204**	**83**	**218**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	99	54	108
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	–	–	–
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	–	–	–
Technical Revisions	1	3	1
Production	(4)	(8)	(5)
December 31, 2014	**96**	**49**	**104**

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	440	244	258	1,157	2,211	4,305	110	5,137
Discoveries	1	–	–	–	–	14	1	5
Extensions	7	29	–	91	–	121	5	152
Infill Drilling	4	12	–	–	–	562	32	142
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	31	–	–	–	–	1,407	34	300
Dispositions	(1)	–	–	–	–	(1)	–	(1)
Economic Factors	(17)	(1)	–	–	(4)	(58)	(1)	(33)
Technical Revisions	9	(3)	34	8	(9)	219	20	97
Production	(29)	(52)	(18)	(39)	(40)	(568)	(13)	(288)
December 31, 2014	**445**	**229**	**274**	**1,217**	**2,158**	**6,001**	**188**	**5,511**

Reconciliation of Company Gross Reserves

As of December 31, 2014
Forecast Prices and Costs

PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	49	90	104	1,013	1,078	1,721	64	2,685
Discoveries	1	–	–	–	–	3	–	1
Extensions	5	12	–	43	358	57	3	431
Infill Drilling	3	4	1	–	–	179	11	49
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	9	–	–	–	–	485	13	103
Dispositions	–	–	–	–	–	–	–	–
Economic Factors	–	–	–	–	(7)	6	–	(5)
Technical Revisions	(9)	(18)	16	39	6	(394)	(21)	(54)
Production	–	–	–	–	–	–	–	–
December 31, 2014	**58**	**88**	**121**	**1,095**	**1,435**	**2,057**	**70**	**3,210**

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	101	34	107
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	–	–	–
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	13	2	13
Technical Revisions	(10)	(5)	(11)
Production	–	–	–
December 31, 2014	**104**	**31**	**109**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	54	49	62
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	–	–	–
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	1	1	1
Technical Revisions	(2)	(1)	(2)
Production	–	–	–
December 31, 2014	**53**	**49**	**61**

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	204	90	104	1,013	1,078	1,804	64	2,854
Discoveries	1	–	–	–	–	3	–	1
Extensions	5	12	–	43	358	57	3	431
Infill Drilling	3	4	1	–	–	179	11	49
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	9	–	–	–	–	485	13	103
Dispositions	–	–	–	–	–	–	–	–
Economic Factors	14	–	–	–	(7)	9	–	9
Technical Revisions	(21)	(18)	16	39	6	(400)	(21)	(67)
Production	–	–	–	–	–	–	–	–
December 31, 2014	**215**	**88**	**121**	**1,095**	**1,435**	**2,137**	**70**	**3,380**

Reconciliation of Company Gross Reserves

As of December 31, 2014
Forecast Prices and Costs

PROVED PLUS PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	166	334	362	2,170	3,289	5,881	174	7,475
Discoveries	2	–	–	–	–	17	1	6
Extensions	12	41	–	134	358	178	8	583
Infill Drilling	6	16	1	–	–	741	43	190
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	40	–	–	–	–	1,892	47	403
Dispositions	(1)	–	–	–	–	(1)	–	(1)
Economic Factors	(1)	(1)	–	–	(11)	(46)	(1)	(21)
Technical Revisions	(2)	(21)	50	47	(3)	(179)	(1)	40
Production	(19)	(52)	(18)	(39)	(40)	(557)	(13)	(276)
December 31, 2014	**203**	**317**	**395**	**2,312**	**3,593**	**7,926**	**258**	**8,399**

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	325	125	346
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	1	–	1
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	(3)	(4)	(4)
Technical Revisions	(9)	(4)	(9)
Production	(6)	(3)	(7)
December 31, 2014	**308**	**114**	**327**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	153	103	170
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	–	–	–
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	1	1	1
Technical Revisions	(1)	2	(1)
Production	(4)	(8)	(5)
December 31, 2014	**149**	**98**	**165**

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	644	334	362	2,170	3,289	6,109	174	7,991
Discoveries	2	–	–	–	–	17	1	6
Extensions	12	41	–	134	358	178	8	583
Infill Drilling	7	16	1	–	–	741	43	191
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	40	–	–	–	–	1,892	47	403
Dispositions	(1)	–	–	–	–	(1)	–	(1)
Economic Factors	(3)	(1)	–	–	(11)	(49)	(1)	(24)
Technical Revisions	(12)	(21)	50	47	(3)	(181)	(1)	30
Production	(29)	(52)	(18)	(39)	(40)	(568)	(13)	(288)
December 31, 2014	**660**	**317**	**395**	**2,312**	**3,593**	**8,138**	**258**	**8,891**

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:*

	2015	*2016*	*2017*	*2018*	*2019*	*Average annual increase thereafter*
Crude oil and NGL						
WTI at Cushing (US$/bbl)	65.00	80.00	90.00	91.35	92.72	1.50%
Western Canada Select (C$/bbl)	60.50	75.13	84.52	85.79	87.07	1.50%
Canadian Light Sweet (C$/bbl)	70.35	87.36	98.28	99.75	101.25	1.50%
Edmonton Pentanes+ (C$/bbl)	78.60	97.60	109.80	111.44	113.12	1.50%
North Sea Brent (US$/bbl)	68.00	83.00	93.00	94.40	95.81	1.50%
Natural gas						
AECO (C$/MMBtu)	3.32	3.71	3.90	4.47	5.05	1.50%
BC Westcoast Station 2 (C$/MMBtu)	3.27	3.66	3.85	4.42	5.00	1.50%
Henry Hub Louisiana (US$/MMBtu)	3.25	3.75	4.00	4.50	5.00	1.50%

A foreign exchange rate of 0.8500 US$/C$ for 2015 and 0.8700 US$/C$ after 2015 was used in the 2014 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 2015 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, the construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

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

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

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

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

Management's Discussion and Analysis

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the three months and year ended December 31, 2014 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2013.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the period ended December 31, 2014 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, and adjusted 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 SCO.

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

The following discussion and analysis refers primarily to the Company's financial results for the three months and year ended December 31, 2014 in relation to the comparable periods in 2013 and the third quarter of 2014. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2013, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated March 4, 2015.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Product sales	**$ 4,850**	$ 5,370	$ 4,330	**$ 21,301**	$ 17,945
Net earnings	**$ 1,198**	$ 1,039	$ 413	**$ 3,929**	$ 2,270
Per common share – basic	**$ 1.10**	$ 0.95	$ 0.38	**$ 3.60**	$ 2.08
– diluted	**$ 1.09**	$ 0.94	$ 0.38	**$ 3.58**	$ 2.08
Adjusted net earnings from operations (1)	**$ 756**	$ 984	$ 563	**$ 3,811**	$ 2,435
Per common share – basic	**$ 0.69**	$ 0.90	$ 0.52	**$ 3.49**	$ 2.24
– diluted	**$ 0.69**	$ 0.89	$ 0.52	**$ 3.47**	$ 2.23
Cash flow from operations (2)	**$ 2,368**	$ 2,440	$ 1,782	**$ 9,587**	$ 7,477
Per common share – basic	**$ 2.17**	$ 2.23	$ 1.64	**$ 8.78**	$ 6.87
– diluted	**$ 2.16**	$ 2.21	$ 1.64	**$ 8.74**	$ 6.86
Capital expenditures, net of dispositions	**$ 2,220**	$ 2,175	$ 2,091	**$ 11,744**	$ 7,274

(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 2014***	*Sep 30 2014*	*Dec 31 2013*	***Dec 31 2014***	*Dec 31 2013*
Net earnings as reported	***$ 1,198***	*$ 1,039*	*$ 413*	***$ 3,929***	*$ 2,270*
Share-based compensation, net of tax (1)	***(144)***	*(122)*	*65*	***66***	*135*
Unrealized risk management (gain) loss, net of tax (2)	***(303)***	*(118)*	*(26)*	***(339)***	*32*
Unrealized foreign exchange loss, net of tax (3)	***106***	*185*	*111*	***256***	*226*
Realized foreign exchange loss (gain) on repayment of US dollar debt securities, net of tax (4)	***36***	*–*	*–*	***36***	*(12)*
Gain on corporate acquisitions/disposition of properties, net of tax (5)	***(137)***	*–*	*–*	***(137)***	*(231)*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (6)	***–***	*–*	*–*	***–***	*15*
Adjusted net earnings from operations	***$ 756***	*$ 984*	*$ 563*	***$ 3,811***	*$ 2,435*

(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 fourth quarter of 2014, the Company repaid US$500 million of 1.45% notes and US$350 million of 4.90% notes. During the first quarter of 2013, the Company repaid US$400 million of 5.15% notes.

(5) During the fourth quarter of 2014, the Company recorded an after-tax gain of $137 million related to the acquisition of certain producing crude oil and natural gas properties. 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.

Cash Flow from Operations

($ millions)	*Three Months Ended* **Dec 31 2014**	*Sep 30 2014*	*Dec 31 2013*	*Year Ended* **Dec 31 2014**	*Dec 31 2013*
Net earnings	***$ 1,198***	*$ 1,039*	*$ 413*	***$ 3,929***	*$ 2,270*
Non-cash items:					
Depletion, depreciation and amortization	***1,406***	*1,226*	*1,272*	***4,880***	*4,844*
Share-based compensation	***(144)***	*(122)*	*65*	***66***	*135*
Asset retirement obligation accretion	***49***	*49*	*46*	***193***	*171*
Unrealized risk management (gain) loss	***(404)***	*(150)*	*(30)*	***(451)***	*39*
Unrealized foreign exchange loss	***106***	*185*	*111*	***256***	*226*
Realized foreign exchange loss (gain) on repayment of US dollar debt securities	***36***	*–*	*–*	***36***	*(12)*
Equity loss from investment	***5***	*5*	*1*	***8***	*4*
Deferred income tax expense (recovery)	***253***	*208*	*(96)*	***807***	*31*
Gain on corporate acquisitions/disposition of properties	***(137)***	*–*	*–*	***(137)***	*(289)*
Current income tax on disposition of properties	**–**	*–*	*–*	**–**	*58*
Cash flow from operations	***$ 2,368***	*$ 2,440*	*$ 1,782*	***$ 9,587***	*$ 7,477*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the year ended December 31, 2014 were $3,929 million compared with $2,270 million for the year ended December 31, 2013. Net earnings for the year ended December 31, 2014 included net after-tax income of $118 million compared with net after-tax expenses of $165 million for the year ended December 31, 2013 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses and gains on repayments of long-term debt, gains on corporate acquisitions/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, 2014 were $3,811 million compared with $2,435 million for the year ended December 31, 2013.

Net earnings for the fourth quarter of 2014 were $1,198 million compared with $413 million for the fourth quarter of 2013 and $1,039 million for the third quarter of 2014. Net earnings for the fourth quarter of 2014 included net after-tax income of $442 million compared with net after-tax expenses of $150 million for the fourth quarter of 2013 and net after-tax income of $55 million for the third quarter of 2014 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange loss on repayment of long-term debt, and the gain on corporate acquisitions/disposition of properties. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2014 were $756 million compared with $563 million for the fourth quarter of 2013 and $984 million for the third quarter of 2014.

The increase in adjusted net earnings for the year ended December 31, 2014 from the comparable period in 2013 was primarily due to:

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

partially offset by:

- lower crude oil sales volumes in the Offshore Africa segment; and
- lower crude oil netbacks in the North Sea and Offshore Africa segments.

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

- higher crude oil and NGLs, natural gas, and SCO sales volumes in the North America, Oil Sands Mining and Upgrading and North Sea segments;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar;

partially offset by:

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

The decrease in adjusted net earnings for the fourth quarter of 2014 from the third quarter of 2014 was primarily due to:

- lower crude oil and NGLs netbacks in the North America, North Sea and Offshore Africa segments;
- lower realized SCO prices; and
- lower crude oil sales volumes in the Offshore Africa segment;

partially offset by:

- higher SCO and crude oil and NGLs sales volumes in the Oil Sands Mining and Upgrading and North Sea segment;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar.

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

Cash flow from operations for the year ended December 31, 2014 was $9,587 million compared with $7,477 million for the year ended December 31, 2013. Cash flow from operations for the fourth quarter of 2014 was $2,368 million compared with $1,782 million for the fourth quarter of 2013 and $2,440 million for the third quarter of 2014. 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, together with the impact of lower cash taxes.

Total production before royalties for the year ended December 31, 2014 increased 18% to 790,410 BOE/d from 671,162 BOE/d for the year ended December 31, 2013. Total production before royalties for the fourth quarter of 2014 increased 27% to 860,920 BOE/d from 677,242 BOE/d for the fourth quarter of 2013 and increased 8% from 796,931 BOE/d for the third quarter of 2014.

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 2014**		Sep 30 2014		Jun 30 2014		Mar 31 2014
Product sales	**$**	**4,850**	$	5,370	$	6,113	$	4,968
Net earnings	**$**	**1,198**	$	1,039	$	1,070	$	622
Net earnings per common share								
– basic	**$**	**1.10**	$	0.95	$	0.98	$	0.57
– diluted	**$**	**1.09**	$	0.94	$	0.97	$	0.57

($ millions, except per common share amounts)		Dec 31 2013		Sept 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

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, increased shale oil production in North America, the impact of 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, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, the strong heavy crude oil drilling program, the impact and timing of acquisitions, and the impact of turnarounds at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, as well as natural decline rates, shut-in natural gas production due to pricing and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix and production, the impact of seasonal costs that are dependent on weather, cost optimizations in North America, the impact and timing of acquisitions, and turnarounds at Horizon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in depletion, depreciation and amortization expense in the North Sea resulting from the planned early cessation of production at the Murchison platform, and the impact of turnarounds 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, which 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 acquisitions/disposition of properties** – Fluctuations due to the recognition of gains on corporate acquisitions/dispositions in the fourth quarter of 2014 and the third quarter of 2013.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
WTI benchmark price (US$/bbl)	**$ 73.12**	$ 97.21	$ 97.50	**$ 92.92**	$ 98.00
Dated Brent benchmark price (US$/bbl)	**$ 75.99**	$ 101.90	$ 109.29	**$ 98.85**	$ 108.62
WCS blend differential from WTI (US$/bbl)	**$ 14.26**	$ 20.19	$ 32.21	**$ 19.41**	$ 25.11
WCS blend differential from WTI (%)	**20%**	21%	33%	**21%**	26%
SCO price (US$/bbl)	**$ 71.01**	$ 94.31	$ 88.37	**$ 91.35**	$ 98.18
Condensate benchmark price (US$/bbl)	**$ 70.54**	$ 93.49	$ 94.30	**$ 92.84**	$ 101.67
NYMEX benchmark price (US$/MMBtu)	**$ 3.95**	$ 4.07	$ 3.63	**$ 4.37**	$ 3.67
AECO benchmark price (C$/GJ)	**$ 3.80**	$ 4.00	$ 2.99	**$ 4.19**	$ 3.00
US/Canadian dollar average exchange rate (US$)	**$ 0.8806**	$ 0.9183	$ 0.9529	**$ 0.9054**	$ 0.9710

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are also highly sensitive to fluctuations in foreign exchange rates. For the three months and year ended December 31, 2014 realized prices were impacted by the weaker Canadian dollar, which increased the Canadian dollar sales price the Company received for its crude oil and natural gas sales as realized pricing is based on US dollar denominated benchmarks.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$92.92 per bbl for the year ended December 31, 2014, a decrease of 5% from US$98.00 per bbl for the year ended December 31, 2013. WTI averaged US$73.12 per bbl for the fourth quarter of 2014, a decrease of 25% from US$97.50 per bbl for the fourth quarter of 2013, and a decrease of 25% from US$97.21 per bbl for the third quarter of 2014.

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$98.85 per bbl for the year ended December 31, 2014, a decrease of 9% from US$108.62 per bbl for the year ended December 31, 2013. Brent averaged US$75.99 per bbl for the fourth quarter of 2014, a decrease of 30% from US$109.29 per bbl for the fourth quarter of 2013, and a decrease of 25% from US$101.90 per bbl for the third quarter of 2014.

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. An oversupply in the world market contributed to a significant decrease in crude oil benchmark pricing in the fourth quarter of 2014. The Organization of the Petroleum Exporting Countries' ("OPEC") decision in November 2014 to not reduce crude oil production to offset the excess world supply continues to put downward pressure on benchmark pricing. In January 2015, WTI averaged US$47.33 per bbl and Brent averaged US$48.07 per bbl and in February, WTI averaged US$50.72 per bbl and Brent averaged US$57.93 per bbl. The Brent differential from WTI tightened for the three months and year ended December 31, 2014 from the comparable periods due to continued debottlenecking of logistical constraints from Cushing to the US Gulf Coast in the first half of 2014.

The WCS Heavy Differential averaged 21% for year ended December 31, 2014 compared with 26% for the year ended December 31, 2013. The WCS Heavy Differential averaged 20% for the fourth quarter of 2014 compared with 33% for the fourth quarter of 2013 and 21% for the third quarter of 2014. The WCS Heavy Differential tightened for the three months and year ended December 31, 2014 from the comparable periods in 2013 as the comparable periods in 2013 reflected lower heavy oil demand due to unplanned refinery disruptions and pipeline logistical constraints. In January 2015, the WCS Heavy Differential averaged US$16.90 per bbl or 36% and in February 2015, the WCS Heavy Differential averaged US$14.20 per bbl or 28%. To partially mitigate its exposure to fluctuating heavy crude oil differentials, the Company entered into 30,000 bbl/d of crude oil WCS differential swaps for the first quarter of 2015 at a weighted average fixed WCS differential of US$21.49 per bbl.

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

The SCO price averaged US$91.35 per bbl for the year ended December 31, 2014, a decrease of 7% from US$98.18 per bbl for the year ended December 31, 2013. The SCO price averaged US$71.01 per bbl for the fourth quarter of 2014, a decrease of 20% from US$88.37 per bbl for the fourth quarter of 2013, and decreased 25% from US$94.31 per bbl for the third quarter of 2014. The decrease in SCO pricing for the three months and year ended December 31, 2014 from the comparable periods was primarily due to a decrease in WTI benchmark pricing.

NYMEX natural gas prices averaged US$4.37 per MMBtu for the year ended December 31, 2014, an increase of 19% from US$3.67 per MMBtu for the year ended December 31, 2013. NYMEX natural gas prices averaged US$3.95 per MMBtu for the fourth quarter of 2014, an increase of 9% from US$3.63 per MMBtu for the fourth quarter of 2013, and a decrease of 3% from US$4.07 per MMBtu for the third quarter of 2014.

AECO natural gas prices for the year ended December 31, 2014 averaged $4.19 per GJ, an increase of 40% from $3.00 per GJ for the year ended December 31, 2013. AECO natural gas prices for the fourth quarter of 2014 averaged $3.80 per GJ, an increase of 27% from $2.99 per GJ for the fourth quarter of 2013, and a decrease of 5% from $4.00 per GJ for the third quarter of 2014.

Natural gas prices increased for the three months and year ended December 31, 2014 from the comparable periods in 2013 due to the drawdown of natural gas storage inventories as a result of colder than normal winter temperatures in 2014. Natural gas prices decreased for the fourth quarter of 2014 from the third quarter of 2014 due to the strong growth in US natural gas production. Growing US natural gas production resulted in natural gas inventories returning to normal industry levels by the end of 2014, leading to downward pressure on natural gas prices.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**409,976**	404,114	332,231	**390,814**	343,699
North America – Oil Sands Mining and Upgrading [(1)]	**128,090**	82,012	112,273	**110,571**	100,284
North Sea	**21,927**	18,197	20,155	**17,380**	18,334
Offshore Africa	**12,047**	13,684	13,379	**12,429**	15,923
	572,040	518,007	478,038	**531,194**	478,240
Natural gas (MMcf/d)					
North America	**1,705**	1,644	1,165	**1,527**	1,130
North Sea	**10**	7	7	**7**	4
Offshore Africa	**18**	23	23	**21**	24
	1,733	1,674	1,195	**1,555**	1,158
Total barrels of oil equivalent (BOE/d)	**860,920**	796,931	677,242	**790,410**	671,162
Product mix					
Light and medium crude oil and NGLs	**15%**	16%	16%	**15%**	15%
Pelican Lake heavy crude oil	**6%**	7%	7%	**6%**	7%
Primary heavy crude oil	**17%**	18%	20%	**18%**	20%
Bitumen (thermal oil)	**14%**	14%	11%	**14%**	14%
Synthetic crude oil [(1)]	**15%**	10%	17%	**14%**	15%
Natural gas	**33%**	35%	29%	**33%**	29%
Percentage of product sales [(1) (2)] (excluding Midstream revenue)					
Crude oil and NGLs	**84%**	85%	89%	**85%**	90%
Natural gas	**16%**	15%	11%	**15%**	10%

(1) The Company has commenced production of diesel for internal use at Horizon. Fourth quarter 2014 SCO production before royalties excludes 1,288 bbl/d of SCO consumed internally as diesel (third quarter 2014 – 875 bbl/d; year ended December 31, 2014 – 545 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**343,324**	329,533	285,594	**318,291**	287,428
North America – Oil Sands Mining and Upgrading [(1)]	**121,292**	76,515	106,358	**104,095**	95,098
North Sea	**21,881**	18,062	20,106	**17,313**	18,279
Offshore Africa	**11,203**	12,276	11,351	**11,500**	12,973
	497,700	436,386	423,409	**451,199**	413,778
Natural gas (MMcf/d)					
North America	**1,606**	1,525	1,101	**1,407**	1,080
North Sea	**10**	7	7	**7**	4
Offshore Africa	**16**	19	19	**18**	20
	1,632	1,551	1,127	**1,432**	1,104
Total barrels of oil equivalent (BOE/d)	**769,775**	694,859	611,245	**689,893**	597,835

(1) The Company has commenced production of diesel for internal use at Horizon. Fourth quarter 2014 SCO production before royalties excludes 1,288 bbl/d of SCO consumed internally as diesel (third quarter 2014 – 875 bbl/d; year ended December 31, 2014 – 545 bbl/d).

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, 2014 increased 11% to 531,194 bbl/d from 478,240 bbl/d for the year ended December 31, 2013. Crude oil and NGLs production for the fourth quarter of 2014 increased 20% to 572,040 bbl/d from 478,038 bbl/d for the fourth quarter of 2013 and increased 10% from 518,007 bbl/d for the third quarter of 2014. The increase in production for the three months and year ended December 31, 2014 from the comparable periods in 2013 was primarily due to higher production in the North America segment and strong and reliable production in Horizon. The increase in production for the fourth quarter of 2014 from the third quarter of 2014 was primarily due to the impact of Horizon's successful completion of the coker plant expansion in the third quarter of 2014. Crude oil and NGLs production for the year ended December 31, 2014 was within the Company's previously issued guidance of 531,000 to 557,000 bbl/d.

Natural gas production for the year ended December 31, 2014 increased 34% to 1,555 MMcf/d from 1,158 MMcf/d for the year ended December 31, 2013. Natural gas production for the fourth quarter of 2014 increased 45% to 1,733 MMcf/d from 1,195 MMcf/d for the fourth quarter of 2013 and increased 4% from 1,674 MMcf/d for the third quarter of 2014. The increase in natural gas production for the three months and year ended December 31, 2014 from the comparable periods in 2013 was primarily a result of the acquisitions of producing Canadian natural gas properties in the second quarter of 2014, and the completion of the Septimus drilling program and plant facility expansion in the third quarter of 2013. The increase in natural gas production for the fourth quarter of 2014 from the third quarter of 2014 was primarily due to the completion of minor acquisitions during the fourth quarter of 2014 as well as growth from the current drilling program. Natural gas production for the year ended December 31, 2014 was within the Company's previously issued guidance of 1,550 to 1,570 MMcf/d.

For 2015, annual revised production guidance is targeted to average between 562,000 and 602,000 bbl/d of crude oil and NGLs and between 1,730 and 1,770 MMcf/d of natural gas. First quarter 2015 production guidance is targeted to average between 591,000 and 617,000 bbl/d of crude oil and NGLs and between 1,785 and 1,805 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2014 increased 14% to average 390,814 bbl/d from 343,699 bbl/d for the year ended December 31, 2013. For the fourth quarter of 2014, crude oil and NGLs production increased 23% to average 409,976 bbl/d compared with 332,231 bbl/d for the fourth quarter of 2013 and increased 1% from 404,114 bbl/d for the third quarter of 2014. The increase in production for the three months and year ended December 31, 2014 from the comparable periods in 2013 was primarily due to increased production related to the acquisitions of producing Canadian crude oil properties in the second quarter of 2014, production at the Company's thermal areas including Kirby South, the impact of the heavy crude oil drilling program, and the ramp up of production at Pelican Lake. The increase in production for the fourth quarter of 2014 from the third quarter of 2014 was primarily related to production at Kirby South and NGLs associated with increased natural gas production. Annual 2014 production of crude oil and NGLs was slightly below the Company's previously issued guidance of 392,000 to 409,000 bbl/d. First quarter 2015 production guidance is targeted to average between 427,000 and 442,000 bbl/d of crude oil and NGLs.

Natural gas production for the year ended December 31, 2014 increased 35% to 1,527 MMcf/d compared with 1,130 MMcf/d for the year ended December 31, 2013. Natural gas production increased 46% to 1,705 MMcf/d for the fourth quarter of 2014 compared with 1,165 MMcf/d in the fourth quarter of 2013 and increased 4% from 1,644 MMcf/d for the third quarter of 2014. The increase in natural gas production for the three months and year ended December 31, 2014 from the comparable periods in 2013 was primarily a result of the acquisitions of producing Canadian natural gas properties in the second quarter of 2014, and the completion of the Septimus drilling program and plant facility expansion in the third quarter of 2013. The increase in natural gas production for the fourth quarter of 2014 from the third quarter of 2014 was primarily due to the completion of minor acquisitions during the fourth quarter of 2014 as well as growth from the current drilling program.

North America – Oil Sands Mining and Upgrading

Production for the year ended December 31, 2014 increased 10% to average 110,571 bbl/d from 100,284 bbl/d for the year ended December 31, 2013. For the fourth quarter of 2014, SCO production increased 14% to 128,090 bbl/d from 112,273 bbl/d for the fourth quarter of 2013 and increased 56% from 82,012 bbl/d for the third quarter of 2014. Production increased for the three months and year ended December 31, 2014 from the comparable periods in 2013 due to increased plant reliability and the successful completion of the coker plant expansion during the third quarter of 2014. Production increased for the fourth quarter 2014 from the third quarter of 2014 due to the coker plant expansion in the third quarter of 2014. Annual 2014 production of SCO was within the Company's previously issued guidance of 109,000 to 115,000 bbl/d. First quarter 2015 production guidance is targeted to average between 129,000 and 136,000 bbl/d.

North Sea

North Sea crude oil production for the year ended December 31, 2014 decreased 5% to 17,380 bbl/d from 18,334 bbl/d for the year ended December 31, 2013. Fourth quarter 2014 crude oil production increased 9% to 21,927 bbl/d from 20,155 bbl/d for the fourth quarter of 2013, and increased 20% from 18,197 bbl/d for the third quarter of 2014. Production for the year ended December 31, 2014 reflected the impact of reinstatement of production from the Banff FPSO in July 2014, which had been offline since December 2011 after suffering storm damage. Production for the year ended December 31, 2014 also reflected the cessation of production due to the planned early decommissioning of the Murchison platform which commenced in the fourth quarter of 2013, unplanned downtime on the Tiffany platform, and natural field declines. The increase in production for the three months ended December 31, 2014 from the comparable periods was primarily due to the reinstatement of production at the Banff FPSO, partially offset by the unplanned downtime on the Tiffany platform.

Offshore Africa

Offshore Africa crude oil production decreased 22% to 12,429 bbl/d for the year ended December 31, 2014 from 15,923 bbl/d for the year ended December 31, 2013. Fourth quarter 2014 crude oil production averaged 12,047 bbl/d, decreasing 10% from 13,379 bbl/d for the fourth quarter of 2013 and decreasing 12% from 13,684 bbl/d for the third quarter of 2014. The decrease in production volumes for the three months and year ended December 31, 2014 from the comparable periods was primarily due to natural field declines.

International Guidance

First quarter 2015 production guidance is targeted to average between 35,000 and 39,000 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 storage facilities, pipelines, or FPSOs, as follows:

(bbl)	**Dec 31 2014**	Sep 30 2014	Dec 31 2013
North America – Exploration and Production	**930,116**	942,861	830,673
North America – Oil Sands Mining and Upgrading (SCO)	**1,266,063**	990,243	1,550,857
North Sea	**368,808**	752,276	385,073
Offshore Africa	**461,997**	706,213	185,476
	3,026,984	3,391,593	2,952,079

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Crude oil and NGLs ($/bbl) [1]					
Sales price [2]	**$ 62.80**	$ 79.99	$ 69.38	**$ 77.04**	$ 73.81
Transportation	**2.15**	2.32	1.84	**2.41**	2.22
Realized sales price, net of transportation	**60.65**	77.67	67.54	**74.63**	71.59
Royalties	**9.05**	13.66	8.82	**12.99**	11.13
Production expense	**18.69**	15.99	18.59	**18.25**	17.14
Netback	**$ 32.91**	$ 48.02	$ 40.13	**$ 43.39**	$ 43.32
Natural gas ($/Mcf) [1]					
Sales price [2]	**$ 4.32**	$ 4.54	$ 3.62	**$ 4.83**	$ 3.58
Transportation	**0.28**	0.26	0.28	**0.27**	0.28
Realized sales price, net of transportation	**4.04**	4.28	3.34	**4.56**	3.30
Royalties	**0.24**	0.32	0.21	**0.38**	0.18
Production expense	**1.39**	1.45	1.37	**1.48**	1.42
Netback	**$ 2.41**	$ 2.51	$ 1.76	**$ 2.70**	$ 1.70
Barrels of oil equivalent ($/BOE) [1]					
Sales price [2]	**$ 48.23**	$ 59.56	$ 53.30	**$ 58.48**	$ 56.46
Transportation	**2.05**	2.08	1.83	**2.18**	2.10
Realized sales price, net of transportation	**46.18**	57.48	51.47	**56.30**	54.36
Royalties	**6.10**	9.12	6.23	**8.90**	7.74
Production expense	**14.66**	13.15	15.04	**14.67**	14.24
Netback	**$ 25.42**	$ 35.21	$ 30.20	**$ 32.73**	$ 32.38

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 61.28**	$ 78.38	$ 62.70	**$ 75.09**	$ 69.90
North Sea	**$ 83.32**	$ 113.08	$ 113.84	**$ 106.63**	$ 112.46
Offshore Africa	**$ 68.90**	$ 104.82	$ 108.25	**$ 97.81**	$ 110.21
Company average	**$ 62.80**	$ 79.99	$ 69.38	**$ 77.04**	$ 73.81
Natural gas ($/Mcf) (1) (2)					
North America	**$ 4.22**	$ 4.43	$ 3.46	**$ 4.72**	$ 3.43
North Sea	**$ 8.22**	$ 6.93	$ 5.05	**$ 7.07**	$ 5.69
Offshore Africa	**$ 11.73**	$ 11.73	$ 11.13	**$ 11.98**	$ 10.45
Company average	**$ 4.32**	$ 4.54	$ 3.62	**$ 4.83**	$ 3.58
Company average ($/BOE) (1) (2)	**$ 48.23**	$ 59.56	$ 53.30	**$ 58.48**	$ 56.46

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

North America

North America realized crude oil prices increased 7% to average $75.09 per bbl for the year ended December 31, 2014 from $69.90 per bbl for the year ended December 31, 2013. North America realized crude oil prices averaged $61.28 per bbl for the fourth quarter of 2014, a decrease of 2% compared with $62.70 per bbl for the fourth quarter of 2013 and a decrease of 22% compared with $78.38 per bbl for the third quarter of 2014. The increase in realized crude oil prices for the year ended December 31, 2014 from the comparable period was primarily due to tightening WCS Heavy Differentials and the impact of a weakening Canadian dollar, partially offset by lower WTI benchmark pricing. The decrease in realized crude oil prices for the fourth quarter of 2014 from the comparable periods was primarily due to lower WTI benchmark pricing, partially offset by the impact of a weakening Canadian dollar. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2014 contributed approximately 155,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 38% to average $4.72 per Mcf for the year ended December 31, 2014 from $3.43 per Mcf for the year ended December 31, 2013. North America realized natural gas prices increased 22% to average $4.22 per Mcf for the fourth quarter of 2014 compared with $3.46 per Mcf in the fourth quarter of 2013, and decreased 5% compared with $4.43 per Mcf for the third quarter of 2014. The increase in realized natural gas prices for the three months and year ended December 31, 2014 from the comparable periods in 2013 was due to the drawdown of natural gas storage inventories as a result of colder than normal winter temperatures in 2014. The decrease in realized natural gas prices for the fourth quarter of 2014 from the third quarter of 2014 was due to the strong growth in US natural gas production.

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

(Quarterly Average)	**Dec 31 2014**	Sep 30 2014	Dec 31 2013
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 62.27**	$ 77.79	$ 70.91
Pelican Lake heavy crude oil ($/bbl)	**$ 62.33**	$ 81.52	$ 60.19
Primary heavy crude oil ($/bbl)	**$ 62.47**	$ 79.70	$ 61.75
Bitumen (thermal oil) ($/bbl)	**$ 58.64**	$ 75.81	$ 57.97
Natural gas ($/Mcf)	**$ 4.22**	$ 4.43	$ 3.46

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

North Sea

North Sea realized crude oil prices decreased 5% to average $106.63 per bbl for the year ended December 31, 2014 from $112.46 per bbl for the year ended December 31, 2013. Realized crude oil prices decreased 27% to average $83.32 per bbl for the fourth quarter of 2014 from $113.84 per bbl for the fourth quarter of 2013 and decreased 26% from $113.08 per bbl for the third quarter of 2014. The decrease in realized crude oil prices for the three months and year ended December 31, 2014 from the comparable periods reflected movements in Brent benchmark pricing and the timing of liftings, partially offset by the weakening of the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 11% to average $97.81 per bbl for the year ended December 31, 2014 from $110.21 per bbl for the year ended December 31, 2013. Realized crude oil prices decreased 36% to average $68.90 per bbl for the fourth quarter of 2014 from $108.25 per bbl for the fourth quarter of 2013 and decreased 34% from $104.82 per bbl for the third quarter of 2014. The decrease in realized crude oil prices for the three months ended December 31, 2014 from the comparable periods reflected movements in Brent benchmark pricing and the timing of liftings, partially offset by the weakening of the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 9.76**	$ 13.99	$ 8.66	**$ 13.74**	$ 11.30
North Sea	**$ 0.17**	$ 0.84	$ 0.28	**$ 0.33**	$ 0.33
Offshore Africa	**$ 4.83**	$ 10.79	$ 16.41	**$ 6.83**	$ 18.18
Company average	**$ 9.05**	$ 13.66	$ 8.82	**$ 12.99**	$ 11.13
Natural gas ($/Mcf) (1)					
North America	**$ 0.23**	$ 0.30	$ 0.17	**$ 0.36**	$ 0.14
Offshore Africa	**$ 0.99**	$ 1.88	$ 2.04	**$ 1.74**	$ 1.83
Company average	**$ 0.24**	$ 0.32	$ 0.21	**$ 0.38**	$ 0.18
Company average ($/BOE) (1)	**$ 6.10**	$ 9.12	$ 6.23	**$ 8.90**	$ 7.74

(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, 2014 compared with the year ended December 31, 2013 reflected movements in benchmark commodity prices and fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 19% of product sales for the year ended December 31, 2014 compared with 17% for the year ended December 31, 2013. Crude oil and NGLs royalties averaged approximately 17% of product sales for the fourth quarter of 2014 compared with 14% for the fourth quarter of 2013 and 18% for the third quarter of 2014. The increase in royalties for the three months and year ended December 31, 2014 from the comparable periods in 2013 was primarily due to higher 2014 annual realized crude oil prices. The decrease in royalties in the fourth quarter of 2014 from the third quarter of 2014 was primarily due to the decrease in realized crude oil prices. Crude oil and NGLs royalties per bbl are anticipated to average 11.5% to 13.5% of product sales for 2015.

Natural gas royalties averaged approximately 8% of product sales for the year ended December 31, 2014 compared with 5% for the year ended December 31, 2013. Natural gas royalties averaged approximately 6% of product sales for the fourth quarter of 2014 compared with 5% for the fourth quarter of 2013 and 7% for the third quarter of 2014. The increase in natural gas royalty rates for the three months and year ended December 31, 2014 from the comparable periods in 2013 was due to higher realized natural gas prices. The decrease in natural gas royalty rates in the fourth quarter of 2014 from the third quarter of 2014 was primarily due to the decrease in realized natural gas prices. Natural gas royalties are anticipated to average 3% to 4% of product sales for 2015.

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 8% for the year ended December 31, 2014 compared to 17% for the year ended December 31, 2013. Royalty rates as a percentage of product sales averaged approximately 7% for the fourth quarter of 2014 compared with 15% for the fourth quarter of 2013 and 11% for the third quarter of 2014. The decrease in royalties for the year ended December 31, 2014 compared with the year ended December 31, 2013 was primarily due to lower realized crude oil prices in 2014 and adjustments to royalties on liftings in 2013. The decrease in royalties for the three months ended December 31, 2014 from the comparable periods was primarily a result of lower realized crude oil prices in the fourth quarter of 2014 and the timing of liftings from various fields. Offshore Africa royalty rates are anticipated to average 3.5% to 5.5% of product sales for 2015.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 14.38**	$ 14.52	$ 14.46	**$ 14.98**	$ 14.20
North Sea	**$ 68.64**	$ 76.48	$ 65.41	**$ 74.04**	$ 66.19
Offshore Africa	**$ 50.54**	$ 27.20	$ 29.31	**$ 43.97**	$ 25.32
Company average	**$ 18.69**	$ 15.99	$ 18.59	**$ 18.25**	$ 17.14
Natural gas ($/Mcf) [1]					
North America	**$ 1.34**	$ 1.36	$ 1.32	**$ 1.42**	$ 1.39
North Sea	**$ 6.35**	$ 19.21	$ 4.81	**$ 9.10**	$ 4.67
Offshore Africa	**$ 3.35**	$ 2.68	$ 2.73	**$ 3.22**	$ 2.53
Company average	**$ 1.39**	$ 1.45	$ 1.37	**$ 1.48**	$ 1.42
Company average ($/BOE) [1]	**$ 14.66**	$ 13.15	$ 15.04	**$ 14.67**	$ 14.24

(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, 2014 increased 5% to $14.98 per bbl from $14.20 per bbl for the year ended December 31, 2013. North America crude oil and NGLs production expense for the fourth quarter of 2014 decreased 1% to $14.38 per bbl from $14.46 per bbl for the fourth quarter of 2013 and decreased 1% from $14.52 per bbl for the third quarter of 2014. The increase in production expense for the year ended December 31, 2014 from the comparable period in 2013 was primarily due to higher trucking and fuel costs across the heavy crude oil and thermal areas, together with higher servicing costs related to heavy crude oil production. The decrease in production expense for the fourth quarter of 2014 from the fourth quarter of 2013 was primarily due to lower production expense in the Pelican Lake and thermal areas. The decrease in production expense for the fourth quarter of 2014 from the third quarter of 2014 reflected the Company's continuous focus on cost control. North America crude oil and NGLs production expense was within the Company's previously issued guidance of $13.00 to $15.00 per bbl and is anticipated to average $12.50 to $14.50 per bbl for 2015.

North America natural gas production expense for the year ended December 31, 2014 increased 2% to $1.42 per Mcf from $1.39 per Mcf for the year ended December 31, 2013. North America natural gas production expense for the fourth quarter of 2014 increased 2% to $1.34 per Mcf from $1.32 per Mcf for the fourth quarter of 2013 and decreased 1% from $1.36 per Mcf for the third quarter of 2014. Natural gas production expense for the three months and year ended December 31, 2014 increased from the comparable periods in 2013 due to the acquisitions of producing Canadian natural gas properties in the second quarter of 2014 that had higher production expense per Mcf than the Company's existing properties. Production expense declined as expected in the fourth quarter of 2014 from the third quarter of 2014, reflecting the successful integration of the acquired assets into the Company's operations. North America natural gas production expense was within the Company's previously issued guidance of $1.35 to $1.45 per bbl and is anticipated to average $1.30 to $1.40 per Mcf for 2015.

North Sea

North Sea crude oil production expense for the year ended December 31, 2014 increased 12% to $74.04 per bbl from $66.19 per bbl for the year ended December 31, 2013. North Sea crude oil production expense for the fourth quarter of 2014 increased 5% to $68.64 per bbl from $65.41 per bbl for the fourth quarter of 2013 and decreased 10% from $76.48 per bbl for the third quarter of 2014. Production expense increased for the year ended December 31, 2014 from the comparable period in 2013 due to natural field declines on relatively fixed cost structure in the North Sea, the impact of the unplanned downtime on the Tiffany platform and a weaker Canadian dollar. The increase in production expense for the fourth quarter of 2014 from the fourth quarter of 2013 was primarily due to the impact of a weaker Canadian dollar, partially offset by the impact of higher production in the fourth quarter of 2014. The decrease in production expense for the fourth quarter of 2014 from the third quarter of 2014 was the result of higher production volumes on a relatively fixed cost structure, partially offset by the impact of product inventory valuation adjustments in the fourth quarter of 2014. North Sea crude oil production expense is anticipated to average $48.00 to $52.00 per bbl for 2015 as the Banff FPSO has returned to the field and production has been reinstated.

Offshore Africa

Offshore Africa crude oil production expense for the year ended December 31, 2014 increased 74% to $43.97 per bbl from $25.32 per bbl for the year ended December 31, 2013. Offshore Africa crude oil production expense for the fourth quarter of 2014 averaged $50.54 per bbl, an increase of 72% from $29.31 per bbl for the fourth quarter of 2013 and an increase of 86% from $27.20 per bbl for the third quarter of 2014. The increase in production expense for the three months and year ended December 31, 2014 from the comparable periods primarily reflects the impact of natural field declines on relatively fixed costs, the timing of liftings from various fields, which have different cost structures, a weaker Canadian dollar, and the impact of product inventory valuation adjustments in Olowi, Gabon during the fourth quarter of 2014. In Offshore Africa, crude oil production expense is anticipated to average $30.00 to $34.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Expense ($ millions)	**$ 1,210**	$ 1,087	$ 1,133	**$ 4,275**	$ 4,254
$/BOE (1)	**$ 17.76**	$ 16.54	$ 21.20	**$ 17.27**	$ 20.38

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

Depletion, depreciation and amortization expense for the year ended December 31, 2014 decreased 15% to $17.27 per BOE from $20.38 per BOE for the year ended December 31, 2013. Depletion, depreciation and amortization expense for the fourth quarter of 2014 decreased 16% to $17.76 per BOE from $21.20 per BOE for the fourth quarter of 2013 and increased 7% from $16.54 per BOE for the third quarter of 2014. Depletion, depreciation and amortization expense decreased on a per barrel basis for the three months and year ended December 31, 2014 from the comparable periods in 2013 due to the impact of lower depletion, depreciation and amortization expense in the North Sea resulting from the planned early cessation of production at the Murchison field in 2013 as well as the impact of increased production on component depreciation determined on a straight-line basis. Depletion, depreciation and amortization expense increased on a per barrel basis for the fourth quarter of 2014 from the third quarter of 2014 primarily due to a revision of Murchison abandonment cost estimates.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Expense ($ millions)	**$ 37**	$ 37	$ 38	**$ 146**	$ 137
$/BOE [1]	**$ 0.56**	$ 0.56	$ 0.71	**$ 0.59**	$ 0.66

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

Asset retirement obligation accretion expense for the year ended December 31, 2014 decreased 11% to $0.59 per BOE from $0.66 per BOE for the year ended December 31, 2013. Asset retirement obligation accretion expense for the fourth quarter of 2014 decreased 21% to $0.56 per BOE from $0.71 per BOE for the fourth quarter of 2013 and was comparable with the third quarter of 2014. Asset retirement obligation accretion expense on a per barrel basis decreased for the three months and year ended December 31, 2014 from the comparable periods in 2013 primarily due to the impact of increased sales volumes.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. During the fourth quarter of 2014, operating performance continued to be strong, leading to average production of 128,090 bbl/d.

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

	Three Months Ended			Year Ended	
($/bbl)	**Dec 31 2014**	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
SCO sales price [1]	**$ 79.23**	$ 103.91	$ 92.05	**$ 100.27**	$ 100.75
Bitumen value for royalty purposes [1] [2]	**$ 56.98**	$ 74.11	$ 55.45	**$ 67.63**	$ 65.48
Bitumen royalties [1] [3]	**$ 4.44**	$ 7.17	$ 5.06	**$ 5.77**	$ 5.11
Transportation	**$ 1.76**	$ 2.28	$ 1.51	**$ 1.85**	$ 1.57

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

Realized SCO sales prices for the year ended December 31, 2014 were comparable with the year ended December 31, 2013. Realized SCO sales prices averaged $79.23 per bbl for the fourth quarter of 2014, a decrease of 14% compared with $92.05 per bbl for the fourth quarter of 2013 and a decrease of 24% compared with $103.91 per bbl for the third quarter of 2014, 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 2014**	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Cash production costs	**$ 395**	$ 398	$ 389	**$ 1,609**	$ 1,567
Less: costs incurred during turnaround periods	**–**	(98)	–	**(98)**	(104)
Adjusted cash production costs	**$ 395**	$ 300	$ 389	**$ 1,511**	$ 1,463
Adjusted cash production costs, excluding natural gas costs	**$ 368**	$ 280	$ 362	**$ 1,395**	$ 1,359
Adjusted natural gas costs	**27**	20	27	**116**	104
Adjusted cash production costs	**$ 395**	$ 300	$ 389	**$ 1,511**	$ 1,463

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2014**	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Adjusted cash production costs, excluding natural gas costs	**$ 31.97**	$ 34.65	$ 36.31	**$ 34.33**	$ 37.68
Adjusted natural gas costs	**2.37**	2.48	2.74	**2.85**	2.89
Adjusted cash production costs	**$ 34.34**	$ 37.13	$ 39.05	**$ 37.18**	$ 40.57
Sales (bbl/d) (2)	**125,092**	87,826	108,163	**111,351**	98,757

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Sales volumes include turnaround periods.

Adjusted cash production costs averaged $37.18 per bbl for the year ended December 31, 2014, a decrease of 8% compared with $40.57 per bbl for the year ended December 31, 2013. Adjusted cash production costs for the fourth quarter of 2014 averaged $34.34 per bbl, a decrease of 12% compared with $39.05 per bbl for the fourth quarter of 2013 and a decrease of 8% compared with $37.13 per bbl for the third quarter of 2014. The decrease in adjusted cash production costs for the three months and year ended December 31, 2014 from comparable periods reflected increased plant capacity and reliability and the corresponding impact of higher production volumes on a relatively fixed cost structure, excluding the turnaround periods. Adjusted cash production costs are anticipated to average $32.00 to $35.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2014**	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Depletion, depreciation and amortization	**$ 194**	$ 137	$ 137	**$ 596**	$ 582
Less: depreciation incurred during turnaround periods	**–**	(28)	–	**(28)**	(79)
Adjusted depletion, depreciation and amortization	**$ 194**	$ 109	$ 137	**$ 568**	$ 503
$/bbl (1)	**$ 16.85**	$ 13.43	$ 13.75	**$ 13.97**	$ 13.95

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

Adjusted depletion, depreciation and amortization expense on a per barrel basis for the year ended December 31, 2014 was comparable with the year ended December 31, 2013. Adjusted depletion, depreciation and amortization expense on a per barrel basis for the fourth quarter of 2014 increased 23% to $16.85 per bbl from $13.75 per bbl for the fourth quarter of 2013 and increased 25% from $13.43 per bbl for the third quarter of 2014. Adjusted depletion, depreciation and amortization expense on a per barrel basis increased for the fourth quarter of 2014 from the comparable periods primarily due to the impact of minor asset derecognitions.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Expense ($ millions)	**$ 12**	$ 12	$ 8	**$ 47**	$ 34
$/bbl [(1)]	**$ 1.02**	$ 1.45	$ 0.85	**$ 1.16**	$ 0.94

(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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2014**	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Revenue	**$ 29**	$ 30	$ 26	**$ 120**	$ 110
Production expense	**7**	8	8	**34**	34
Midstream cash flow	**22**	22	18	**86**	76
Depreciation	**2**	2	2	**9**	8
Equity loss from investment	**5**	5	1	**8**	4
Segment earnings before taxes	**$ 15**	$ 15	$ 15	**$ 69**	$ 64

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 2014, Redwater Partnership, the Company and APMC amended certain terms of the processing agreements. In conjunction with these amendments, in order to provide financing for Project completion based on the current revised Project cost estimate of approximately $8,500 million, the Company, along with APMC, each committed to provide additional funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2014, the Company and APMC each provided an additional $113 millon of subordinated debt. Subsequent to December 31, 2014, the Company and APMC each provided an additional $112 million of subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During the second quarter of 2014, Redwater Partnership executed a $3,500 million syndicated credit facility with a group of financial institutions maturing June 2018 and repaid and cancelled its $1,200 million credit facility previously in place. As at December 31, 2014, Redwater Partnership had borrowings of $913 million under the syndicated credit facility.

During the third quarter of 2014, Redwater Partnership issued $500 million of 3.20% series A senior secured bonds due July 2024 and $500 million of 4.05% series B senior secured bonds due July 2044. Subsequent to December 31, 2014, Redwater Partnership issued $500 million of 2.10% series C senior secured bonds due February 2022 and $500 million of 3.70% series D senior secured bonds due February 2043.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

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

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2014	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Expense ($ millions)	**$ 100**	$ 87	$ 93	**$ 367**	$ 335
$/BOE (1)	**$ 1.26**	$ 1.17	$ 1.47	**$ 1.28**	$ 1.37

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

Administration expense for the year ended December 31, 2014 decreased 7% to $1.28 per BOE from $1.37 per BOE for the year ended December 31, 2013. Administration expense for the fourth quarter of 2014 decreased 14% to $1.26 per BOE from $1.47 per BOE for the fourth quarter of 2013 and increased 8% from $1.17 per BOE for the third quarter of 2014. Administration expense per BOE decreased for the year ended December 31, 2014 from the comparable periods in 2013 primarily due to the impact of higher sales volumes. Administration expense per BOE increased for the fourth quarter of 2014 from the third quarter of 2014 primarily due to higher staffing related costs.

SHARE-BASED COMPENSATION

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2014**	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
(Recovery) Expense	**$ (144)**	$ (122)	$ 65	**$ 66**	$ 135

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

The Company recorded a $66 million share-based compensation expense for the year ended December 31, 2014, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company's share price. For the year ended December 31, 2014, the Company capitalized $14 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (December 31, 2013 – $25 million).

For the year ended December 31, 2014, the Company paid $8 million for stock options surrendered for cash settlement (December 31, 2013 – $4 million).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts and interest rates)	**Dec 31 2014**	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Expense, gross	**$ 141**	$ 135	$ 113	**$ 527**	$ 454
Less: capitalized interest	**57**	56	53	**204**	175
Expense, net	**$ 84**	$ 79	$ 60	**$ 323**	$ 279
$/BOE (1)	**$ 1.05**	$ 1.06	$ 0.94	**$ 1.12**	$ 1.14
Average effective interest rate	**4.0%**	3.9%	4.4%	**3.9%**	4.4%

(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, 2014 increased from the comparable periods in 2013 primarily due to the impact of higher overall debt levels. Gross interest and other financing expense for the fourth quarter of 2014 was comparable with the third quarter of 2014. Capitalized interest of $204 million for the year ended December 31, 2014 was primarily related to the Horizon Phase 2/3 expansion.

The Company's average effective interest rate for the three months and year ended December 31, 2014 decreased from the comparable periods in 2013 due to the repayment of higher interest rate US dollar debt securities, the issuance of lower interest rate US dollar debt securities, and an increase in the utilization of the lower cost US commercial paper program that was implemented in 2013.

Net interest and other financing expense for the year ended December 31, 2014 decreased 2% to $1.12 per BOE from $1.14 per BOE for the year ended December 31, 2013. Net interest and other financing expense for the fourth quarter of 2014 increased 12% to $1.05 per BOE from $0.94 per BOE for the fourth quarter of 2013 and decreased 1% from $1.06 per BOE for the third quarter of 2014. The decrease on a per barrel basis for the year ended December 31, 2014 from the comparable period was primarily due to the impact of increased sales volumes.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2014**	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Crude oil and NGLs financial instruments	**$ (284)**	$ –	$ 5	**$ (284)**	$ 44
Natural gas financial instruments	**1**	21	–	**34**	–
Foreign currency contracts	**(52)**	(17)	(41)	**(99)**	(160)
Realized (gain) loss	**(335)**	4	(36)	**(349)**	(116)
Crude oil and NGLs financial instruments	**(403)**	(70)	(10)	**(427)**	17
Natural gas financial instruments	**(3)**	(21)	(5)	**(3)**	3
Foreign currency contracts	**2**	(59)	(15)	**(21)**	19
Unrealized (gain) loss	**(404)**	(150)	(30)	**(451)**	39
Net gain	**$ (739)**	$ (146)	$ (66)	**$ (800)**	$ (77)

The Company recorded a net unrealized gain of $451 million ($339 million after-tax) on its risk management activities for the year ended December 31, 2014, including an unrealized gain of $404 million ($303 million after-tax) for the fourth quarter of 2014 (September 30, 2014 – unrealized gain of $150 million; $118 million after-tax; December 31, 2013 – unrealized gain of $30 million; $26 million after-tax).

Complete details related to outstanding derivative financial instruments at December 31, 2014 are disclosed in note 14 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2014**	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Net realized loss (gain)	**$ 18**	$ (1)	$ 3	**$ 47**	$ (16)
Net unrealized loss (1)	**106**	185	111	**256**	226
Net loss	**$ 124**	$ 184	$ 114	**$ 303**	$ 210

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

The net realized foreign exchange loss for the year ended December 31, 2014 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$500 million of 1.45% notes and US$350 million of 4.90% notes. The net unrealized foreign exchange loss for the year ended December 31, 2014 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt, partially offset by the reversal of the net unrealized foreign exchange loss on the repayment of US$500 million of 1.45% notes and US$350 million of 4.90% notes. The net unrealized loss for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2014 – unrealized gain of $115 million, September 30, 2014 – unrealized gain of $153 million, December 31, 2013 – unrealized gain of $85 million; year ended December 31, 2014 – unrealized gain of $259 million; December 31, 2013 – unrealized gain of $165 million). The US/Canadian dollar exchange rate at December 31, 2014 was US$0.8620 (September 30, 2014 – US$0.8922; December 31, 2013 – US$0.9402).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Dec 31 2014	Three Months Ended Sep 30 2014	Three Months Ended Dec 31 2013	Year Ended Dec 31 2014	Year Ended Dec 31 2013
North America (1)	**$ 123**	$ 162	$ 133	**$ 702**	$ 544
North Sea	**(23)**	14	5	**(68)**	23
Offshore Africa (2)	**8**	21	55	**43**	202
PRT (recovery) expense – North Sea	**(86)**	(114)	5	**(273)**	(56)
Other taxes	**5**	6	4	**23**	22
Current income tax expense	**27**	89	202	**427**	735
Deferred income tax expense (recovery)	**254**	158	(36)	**681**	163
Deferred PRT (recovery) expense – North Sea	**(1)**	50	(60)	**126**	(132)
Deferred income tax expense (recovery)	**253**	208	(96)	**807**	31
	$ 280	$ 297	$ 106	**$ 1,234**	$ 766
Income tax rate and other legislative changes (3)	**–**	–	–	**–**	(15)
	$ 280	$ 297	$ 106	**$ 1,234**	$ 751
Effective income tax rate on adjusted net earnings from operations (4)	**25.7%**	24.7%	21.4%	**24.6%**	26.2%

(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 in 2013.

(3) 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.

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

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

The current PRT recovery in the North Sea included the impact of amendments to tax filings for prior years.

For 2015, based on forward commodity prices and the current availability of tax pools, the Company expects to incur current income tax expense of $300 million to $400 million in Canada and recoveries of $190 million to $220 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Dec 31 2014**	Sep 30 2014	Dec 31 2013	Year Ended **Dec 31 2014**	Dec 31 2013
Exploration and Evaluation					
Net expenditures (proceeds) [2][3]	**$ 97**	$ 92	$ 7	**$ 1,190**	$ (144)
Property, Plant and Equipment					
Net property acquisitions [2]	**72**	79	61	**2,893**	246
Well drilling, completion and equipping	**582**	498	600	**2,162**	2,140
Production and related facilities	**482**	504	444	**1,830**	1,878
Capitalized interest and other [4]	**28**	34	34	**106**	120
Net expenditures	**1,164**	1,115	1,139	**6,991**	4,384
Total Exploration and Production	**1,261**	1,207	1,146	**8,181**	4,240
Oil Sands Mining and Upgrading					
Horizon Phase 2/3 construction costs	**739**	670	597	**2,502**	2,057
Sustaining capital	**83**	122	28	**352**	278
Turnaround costs	**8**	15	2	**29**	100
Capitalized interest and other [4]	**32**	38	56	**227**	157
Total Oil Sands Mining and Upgrading	**862**	845	683	**3,110**	2,592
Midstream	**(16)**	27	185	**62**	197
Abandonments [5]	**101**	82	71	**346**	207
Head office	**12**	14	6	**45**	38
Total net capital expenditures	**$ 2,220**	$ 2,175	$ 2,091	**$ 11,744**	$ 7,274
By segment					
North America [2]	**$ 1,029**	$ 997	$ 1,001	**$ 7,500**	$ 4,026
North Sea	**105**	100	95	**400**	334
Offshore Africa [3]	**127**	110	50	**281**	(120)
Oil Sands Mining and Upgrading	**862**	845	683	**3,110**	2,592
Midstream	**(16)**	27	185	**62**	197
Abandonments [5]	**101**	82	71	**346**	207
Head office	**12**	14	6	**45**	38
Total	**$ 2,220**	$ 2,175	$ 2,091	**$ 11,744**	$ 7,274

(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 50% interest in its exploration right in South Africa in 2013.
(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, 2014 were $11,744 million compared with $7,274 million for the year ended December 31, 2013. Net capital expenditures for the fourth quarter of 2014 were $2,220 million compared with $2,091 million for the fourth quarter of 2013 and $2,175 million for the third quarter of 2014.

The increase in capital expenditures for the year ended December 31, 2014 from the comparable period in 2013 was primarily due to the acquisitions of certain Canadian crude oil and natural gas properties during the second quarter of 2014. The increase in capital expenditures for the fourth quarter of 2014 from comparable period in 2013 was primarily due to an increase in well drilling, completion and equipping spending and Horizon Phase 2/3 site construction activity.

On April 1, 2014, the Company completed the acquisition of certain Canadian crude oil and natural gas properties, including exploration and evaluation assets of $823 million, for cash consideration of $3,110 million, subject to final closing adjustments. During the year ended December 31, 2014, the Company also acquired a number of additional producing crude oil and natural gas properties in the North American Exploration and Production segment for net cash consideration of $643 million, resulting in a non-cash gain of $137 million.

Included in the Company's original 2015 budget was approximately $2,000 million of capital flexibility, which allows the Company to reallocate capital over 2015 as required. In response to declining commodity prices, in December 2014 the Company proactively reviewed its capital allocation strategy and in January 2015 announced that it would access this capital flexibility to reduce capital spending by approximately $2,400 million. Subsequently, capital expenditure guidance for 2015 has been further reduced by $150 million as a result of the reduction in scope of the originally planned 2015 Horizon maintenance turnaround from 35 days to 6 days. The Company has significant additional capital flexibility in 2015 to further curtail capital spending if required or to increase capital spending if commodity prices strengthen.

Drilling Activity

	Three Months Ended			Year Ended	
(number of wells)	**Dec 31 2014**	Sep 30 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Net successful natural gas wells	**16**	21	11	**75**	44
Net successful crude oil wells (1)	**325**	273	324	**1,023**	1,117
Dry wells	**8**	6	13	**19**	30
Stratigraphic test / service wells	**74**	11	54	**437**	384
Total	**423**	311	402	**1,554**	1,575
Success rate (excluding stratigraphic test / service wells)	**98%**	98%	96%	**98%**	97%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 66% of the total capital expenditures for the year ended December 31, 2014 compared with approximately 59% for the year ended December 31, 2013.

During the fourth quarter of 2014, the Company targeted 16 net natural gas wells, including 5 wells in Northeast British Columbia, 8 wells in Northwest Alberta and 3 wells in Northern Plains. The Company also targeted 332 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 305 primary heavy crude oil wells were drilled. Another 27 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the fourth quarter of 2014 averaged approximately 119,000 bbl/d compared with approximately 78,100 bbl/d for the fourth quarter of 2013 and approximately 115,300 bbl/d for the third quarter of 2014. Production volumes reflected the cyclic nature of thermal oil production at Primrose and production at Kirby South.

In response to declining commodity prices, in January 2015 the Company deferred development activities in the Kirby North Project.

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

Development of the tertiary recovery conversion projects at Pelican Lake continued. Pelican Lake production averaged approximately 50,700 bbl/d for the fourth quarter of 2014 compared with 46,100 bbl/d for the fourth quarter of 2013 and 51,900 bbl/d for the third quarter of 2014.

In order to expand its pipeline infrastructure, the Company is participating in the expansion of the Cold Lake pipeline system. Initial pipeline commissioning activities are expected to commence in the first quarter of 2015 with the final phases of the project expected to continue for approximately three years.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the fourth quarter of 2014 was focused on field construction of the hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit, tank farms, cooling water tower, tailings, froth treatment, tailings transfer pumphouses and pipelines, extraction plant, and ore preparation plant civil works along with engineering and procurement related to the ore preparation plants, froth treatment plant, sourwater concentrator and combined hydrotreater.

Capital spending in 2015 has been revised from $2,450 million to $2,200 million through targeted cost efficiencies, while maintaining planned expansion activities.

North Sea

In 2014, the Company progressed on its drilling program. Subsequent to December 31, 2014, the Company reduced its 2015 drilling program to one well and suspended all other development activities. The decommissioning activities at the Murchison platform are ongoing and are expected to continue for approximately five years.

Offshore Africa

Subsequent to December 31, 2014 in Côte d'Ivoire, the Company drilled the first well of its ten gross well development program at the Espoir field, with first oil anticipated at the end of the first quarter of 2015. At the Baobab field, the rig arrived on location and the Company commenced drilling the first well of its six gross well program with first oil anticipated in the second quarter of 2015.

In Côte d'Ivoire, during the second quarter of 2014, the operator in Block CI-514 completed drilling an exploratory well and encountered the presence of light oil. The well was plugged and the data gathered will now be evaluated to determine the extent of the accumulation and the forward plan for appraisal. The operator anticipates drilling a second exploratory well in the second quarter of 2015.

In South Africa, during the fourth quarter of 2014, the exploration well drilled on Block 11B/12B was suspended due to mechanical issues with marine equipment on the drilling rig. The rig safely left the well location and, as the available drilling window had ended, it was demobilized by the operator. The South African authorities have formally confirmed that the well drilled satisfies the work obligation for the initial period of the Block 11B/12B Exploration Right. The operator is reviewing the course of action to re-enter the well, and has indicated drilling operations are unlikely to resume in the area before 2016.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Dec 31 2014**		Sep 30 2014		Dec 31 2013
Working capital deficit [1]	**$**	**673**	$	915	$	1,574
Long-term debt [2] [3]	**$**	**14,002**	$	13,685	$	9,661
Share capital	**$**	**4,432**	$	4,388	$	3,854
Retained earnings		**24,408**		23,499		21,876
Accumulated other comprehensive income		**51**		47		42
Shareholders' equity	**$**	**28,891**	$	27,934	$	25,772
Debt to book capitalization [3] [4]		**33%**		33%		27%
Debt to market capitalization [3] [5]		**26%**		22%		20%
After-tax return on average common shareholders' equity [6]		**14%**		12%		9%
After-tax return on average capital employed [3] [7]		**10%**		9%		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, 2014, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2013. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring cash flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. In response to declining commodity prices in late 2014, the Company exercised its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages. During the first quarter of 2015, the Company extended its existing $1,000 million non-revolving term credit facility to January 2017. In addition, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018; and,
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of a default.

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

As at December 31, 2014, the Company had in place bank credit facilities of $5,627 million, of which $2,643 million, net of commercial paper issuances of $580 million, was available for general corporate purposes. Subsequent to December 31, 2014, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018 and extended the existing $1,000 million non-revolving term credit facility originally maturing March 2016 to January 2017.

During the first quarter of 2014, the Company issued US$500 million of three-month LIBOR plus 0.375% notes due March 2016, and concurrently, entered into cross currency swaps to fix the foreign currency exchange rate risk at three-month CDOR plus 0.309% and $555 million. In addition, the Company issued US$500 million of 3.80% notes due April 2024. Proceeds from the securities were used to repay bank indebtedness.

During the second quarter of 2014, the Company issued $500 million of 2.60% medium-term notes due December 2019 and $500 million of 3.55% medium-term notes due June 2024. Proceeds from the securities were used for general corporate purposes and repayment of bank indebtedness.

During the fourth quarter of 2014, the Company issued US$600 million of 1.75% notes due January 2018 and US$600 million of 3.90% notes due February 2025. Proceeds from the securities were used to repay bank indebtedness.

At December 31, 2014, the Company had maturity of long-term debt of $400 million over the next 12 months ($400 million due June 2015).

Long-term debt was $14,002 million at December 31, 2014, resulting in a debt to book capitalization ratio of 33% (September 30, 2014 – 33%; December 31, 2013 – 27%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from 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 2015 at prices that protect investment returns to support 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, 2014 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 4, 2015, 50,000 bbl/d of currently forecasted 2015 crude oil volumes were hedged using price collars. The Company has also entered into 30,000 bbl/d of crude oil WCS differential swaps in the first quarter of 2015. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2014 are discussed in note 14 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at December 31, 2014, there were 1,091,837,000 common shares outstanding (December 31, 2013 – 1,087,322,000 common shares) and 71,708,000 stock options outstanding. As at March 3, 2015, the Company had 1,092,528,000 common shares outstanding and 70,576,000 stock options outstanding.

On March 4, 2015, the Board of Directors approved an increase in the annual dividend to $0.92 per common share, (previous annual dividend rate of $0.90 per common share), beginning with the quarterly dividend payable on April 1, 2015, at $0.23 per common share. This reflects confidence in the Company's cash flow and provides a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

In April 2014, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), during the twelve month period commencing April 2014 and ending April 2015, up to 54,596,899 common shares. The Company's Normal Course Issuer Bid announced in 2013 expired April 2014.

For the year ended December 31, 2014, the Company purchased for cancellation 10,095,000 common shares at a weighted average price of $44.85 per common share, for a total cost of $453 million. Retained earnings were reduced by $414 million, representing the excess of the purchase price of common shares over their average carrying value.

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, 2014:

($ millions)	2015	2016	2017	2018	2019	Thereafter
Product transportation and pipeline	$ 442	$ 334	$ 301	$ 268	$ 237	$ 1,512
Offshore equipment operating leases and offshore drilling	$ 341	$ 92	$ 66	$ 59	$ 19	$ –
Long-term debt (1)	$ 980	$ 2,397	$ 2,153	$ 1,160	$ 1,000	$ 6,395
Interest and other financing expense (2)	$ 555	$ 525	$ 445	$ 378	$ 350	$ 4,202
Office leases	$ 42	$ 42	$ 44	$ 46	$ 47	$ 284
Other	$ 204	$ 125	$ 40	$ 1	$ –	$ –

(1) Long-term debt represents principal repayments only and does not reflect 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, 2014.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, refer to the unaudited interim consolidated financial statements for the year ended December 31, 2014.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgments in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant critical accounting estimates is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2013.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Dec 31 2014**	Dec 31 2013
ASSETS			
Current assets			
Cash and cash equivalents		**$ 25**	$ 16
Accounts receivable		**1,889**	1,427
Current income taxes		**228**	–
Inventory		**665**	632
Prepaids and other		**172**	141
Current portion of other long-term assets	6	**510**	–
		3,489	2,216
Exploration and evaluation assets	4	**3,557**	2,609
Property, plant and equipment	5	**52,480**	46,487
Other long-term assets	6	**674**	442
		$ 60,200	$ 51,754
LIABILITIES			
Current liabilities			
Accounts payable		**$ 564**	$ 637
Accrued liabilities		**3,279**	2,519
Current income taxes		**–**	359
Current portion of long-term debt	7	**980**	1,444
Current portion of other long-term liabilities	8	**319**	275
		5,142	5,234
Long-term debt	7	**13,022**	8,217
Other long-term liabilities	8	**4,175**	4,348
Deferred income taxes		**8,970**	8,183
		31,309	25,982
SHAREHOLDERS' EQUITY			
Share capital	10	**4,432**	3,854
Retained earnings		**24,408**	21,876
Accumulated other comprehensive income	11	**51**	42
		28,891	25,772
		$ 60,200	$ 51,754

Commitments and contingencies (note 15).

Approved by the Board of Directors on March 4, 2015

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Dec 31 2014	Three Months Ended Dec 31 2013	Year Ended Dec 31 2014	Year Ended Dec 31 2013
Product sales		**$ 4,850**	$ 4,330	**$ 21,301**	$ 17,945
Less: royalties		**(466)**	(383)	**(2,438)**	(1,800)
Revenue		**4,384**	3,947	**18,863**	16,145
Expenses					
Production		**1,399**	1,198	**5,265**	4,559
Transportation and blending		**759**	645	**3,232**	2,938
Depletion, depreciation and amortization	5	**1,406**	1,272	**4,880**	4,844
Administration		**100**	93	**367**	335
Share-based compensation	8	**(144)**	65	**66**	135
Asset retirement obligation accretion	8	**49**	46	**193**	171
Interest and other financing expense		**84**	60	**323**	279
Risk management activities	14	**(739)**	(66)	**(800)**	(77)
Foreign exchange loss		**124**	114	**303**	210
Gain on corporate acquisitions/disposition of properties	5	**(137)**	–	**(137)**	(289)
Equity loss from investment	6	**5**	1	**8**	4
		2,906	3,428	**13,700**	13,109
Earnings before taxes		**1,478**	519	**5,163**	3,036
Current income tax expense	9	**27**	202	**427**	735
Deferred income tax expense (recovery)	9	**253**	(96)	**807**	31
Net earnings		**$ 1,198**	$ 413	**$ 3,929**	$ 2,270
Net earnings per common share					
Basic	13	**$ 1.10**	$ 0.38	**$ 3.60**	$ 2.08
Diluted	13	**$ 1.09**	$ 0.38	**$ 3.58**	$ 2.08

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2014	Three Months Ended Dec 31 2013	Year Ended Dec 31 2014	Year Ended Dec 31 2013
Net earnings	**$ 1,198**	$ 413	**$ 3,929**	$ 2,270
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss), net of taxes of $nil (2013 – $3 million) – three months ended; $nil (2013 – $nil) – year ended	**6**	(25)	**5**	(4)
Reclassification to net earnings, net of taxes of $nil (2013 – $nil) – three months ended; $1 million (2013 – $nil) – year ended	**1**	–	**8**	(1)
	7	(25)	**13**	(5)
Foreign currency translation adjustment				
Translation of net investment	**(3)**	–	**(4)**	(11)
Other comprehensive income (loss), net of taxes	**4**	(25)	**9**	(16)
Comprehensive income	**$ 1,202**	$ 388	**$ 3,938**	$ 2,254

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended Dec 31 2014	Dec 31 2013
Share capital	10		
Balance – beginning of year		**$ 3,854**	$ 3,709
Issued upon exercise of stock options		**488**	130
Previously recognized liability on stock options exercised for common shares		**129**	50
Purchase of common shares under Normal Course Issuer Bid		**(39)**	(35)
Balance – end of year		**4,432**	3,854
Retained earnings			
Balance – beginning of year		**21,876**	20,516
Net earnings		**3,929**	2,270
Purchase of common shares under Normal Course Issuer Bid	10	**(414)**	(285)
Dividends on common shares	10	**(983)**	(625)
Balance – end of year		**24,408**	21,876
Accumulated other comprehensive income	11		
Balance – beginning of year		**42**	58
Other comprehensive income (loss) , net of taxes		**9**	(16)
Balance – end of year		**51**	42
Shareholders' equity		**$ 28,891**	$ 25,772

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Dec 31 2014	Three Months Ended Dec 31 2013	Year Ended Dec 31 2014	Year Ended Dec 31 2013
Operating activities					
Net earnings		**$ 1,198**	$ 413	**$ 3,929**	$ 2,270
Non-cash items					
Depletion, depreciation and amortization		**1,406**	1,272	**4,880**	4,844
Share-based compensation		**(144)**	65	**66**	135
Asset retirement obligation accretion		**49**	46	**193**	171
Unrealized risk management (gain) loss		**(404)**	(30)	**(451)**	39
Unrealized foreign exchange loss		**106**	111	**256**	226
Realized foreign exchange loss (gain) on repayment of US dollar debt securities		**36**	–	**36**	(12)
Equity loss from investment		**5**	1	**8**	4
Deferred income tax expense (recovery)		**253**	(96)	**807**	31
Gain on corporate acquisitions/disposition of properties		**(137)**	–	**(137)**	(289)
Current income tax on disposition of properties		**–**	–	**–**	58
Other		**(107)**	(92)	**(38)**	(19)
Abandonment expenditures		**(101)**	(71)	**(346)**	(207)
Net change in non-cash working capital		**158**	563	**(744)**	(33)
		2,318	2,182	**8,459**	7,218
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net		**(362)**	52	**1,195**	803
Issue of medium-term notes, net		**–**	–	**992**	98
Issue (repayment) of US dollar debt securities, net	7	**382**	–	**1,482**	(398)
Issue of common shares on exercise of stock options		**40**	65	**488**	130
Purchase of common shares under Normal Course Issuer Bid		**(49)**	(46)	**(453)**	(320)
Dividends on common shares		**(246)**	(136)	**(955)**	(523)
Net change in non-cash working capital		**(6)**	(6)	**(22)**	(23)
		(241)	(71)	**2,727**	(233)
Investing activities					
Net (expenditures) proceeds on exploration and evaluation assets		**(97)**	(7)	**(1,190)**	144
Net expenditures on property, plant and equipment		**(2,022)**	(2,013)	**(10,208)**	(7,211)
Current income tax on disposition of properties		**–**	–	**–**	(58)
Investment in other long-term assets		**–**	–	**(113)**	–
Net change in non-cash working capital		**51**	(93)	**334**	119
		(2,068)	(2,113)	**(11,177)**	(7,006)
Increase (decrease) in cash and cash equivalents		**9**	(2)	**9**	(21)
Cash and cash equivalents – beginning of period		**16**	18	**16**	37
Cash and cash equivalents – end of period		**$ 25**	$ 16	**$ 25**	$ 16
Interest paid		**$ 134**	**$ 95**	**$ 521**	**$ 460**
Income taxes paid		**$ 127**	**$ 43**	**$ 792**	**$ 357**

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 2100, 855-2 Street S.W., Calgary, Alberta, Canada.

These interim consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34, "Interim Financial Reporting", following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2013, except as discussed in note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2013.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2014, the Company adopted the version of IFRS 9 "Financial Instruments" issued in November 2013. IFRS 9 replaced the sections of IAS 39 "Financial Instruments: Recognition and Measurement" that relate to the classification and measurement of financial instruments and hedge accounting.

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

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

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

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

Effective January 1, 2014, the Company adopted an amendment to IAS 32 "Financial instruments: Presentation" relating to offsetting financial assets and financial liabilities. This amendment clarifies that the right of set-off must not be contingent on a future event. The amendment did not have a significant impact on the Company's consolidated financial statements.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In May 2014, the IASB issued IFRS 15 “Revenue from Contracts with Customers” to provide guidance on the recognition of revenue and cash flows arising from an entity’s contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements. The new standard is required to be adopted retrospectively effective January 1, 2017, with earlier adoption permitted. The Company is currently assessing the impact of IFRS 15 on its consolidated financial statements.

In May 2014, the IASB issued an amendment to IFRS 11 “Joint Arrangements” to clarify the accounting treatment when an entity acquires interests in joint ventures and joint operations. The amendment requires these acquisitions to be accounted for as business combinations. This amendment is effective January 1, 2016 and is to be applied prospectively. Adoption of this amended standard is not expected to result in a significant impact to the Company’s consolidated financial statements.

In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The amendments are effective January 1, 2018. The Company is currently assessing the impact of this amendment on its 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, 2013	$ 2,570	$ –	$ 39	$ –	$ 2,609
Additions	**1,103**	**–**	**87**	**–**	**1,190**
Transfers to property, plant and equipment	**(247)**	**–**	**–**	**–**	**(247)**
Foreign exchange adjustments	**–**	**–**	**5**	**–**	**5**
At December 31, 2014	**$ 3,426**	**$ –**	**$ 131**	**$ –**	**$ 3,557**

During 2014, the Company acquired certain exploration and evaluation assets in connection with the acquisition of crude oil and natural gas properties (refer to note 5).

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, 2013	$ 53,810	$ 5,200	$ 3,356	$ 19,366	$ 508	$ 308	$ 82,548
Additions	**6,858**	**486**	**193**	**2,728**	**62**	**45**	**10,372**
Transfers from E&E assets	**247**	**–**	**–**	**–**	**–**	**–**	**247**
Disposals/derecognitions	**(309)**	**–**	**–**	**(146)**	**–**	**(1)**	**(456)**
Foreign exchange adjustments and other	**–**	**496**	**309**	**–**	**–**	**–**	**805**
At December 31, 2014	**$ 60,606**	**$ 6,182**	**$ 3,858**	**$ 21,948**	**$ 570**	**$ 352**	**$ 93,516**
Accumulated depletion and depreciation							
At December 31, 2013	$ 28,315	$ 3,467	$ 2,551	$ 1,414	$ 111	$ 203	$ 36,061
Expense	**3,880**	**265**	**105**	**596**	**9**	**25**	**4,880**
Disposals/derecognitions	**(309)**	**–**	**–**	**(146)**	**–**	**(1)**	**(456)**
Foreign exchange adjustments and other	**–**	**317**	**234**	**–**	**–**	**–**	**551**
At December 31, 2014	**$ 31,886**	**$ 4,049**	**$ 2,890**	**$ 1,864**	**$ 120**	**$ 227**	**$ 41,036**
Net book value							
– at December 31, 2014	**$ 28,720**	**$ 2,133**	**$ 968**	**$ 20,084**	**$ 450**	**$ 125**	**$ 52,480**
– at December 31, 2013	$ 25,495	$ 1,733	$ 805	$ 17,952	$ 397	$ 105	$ 46,487

Project costs not subject to depletion and depreciation	**Dec 31 2014**	Dec 31 2013
Horizon	**$ 5,492**	$ 4,051
Kirby Thermal Oil Sands – North	**$ 681**	$ 322
Kirby Thermal Oil Sands – South	**$ –**	$ 1,345

On April 1, 2014, the Company completed the acquisition of certain Canadian crude oil and natural gas properties in the North American Exploration and Production segment, including exploration and evaluation assets of $823 million, for cash consideration of $3,110 million, subject to final closing adjustments. The transaction was accounted for using the acquisition method of accounting. In connection with this acquisition, the Company assumed associated asset retirement obligations of $242 million and other long-term liabilities of $49 million. No debt obligations were assumed and no net deferred income tax liabilities were recognized. The above amounts are estimates and may be subject to change based on the receipt of new information.

During 2014, the Company acquired a number of additional producing crude oil and natural gas properties in the North American Exploration and Production segment for net cash consideration of $643 million (year ended December 31, 2013 – $252 million). These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company acquired net working capital of $28 million, assumed associated asset retirement obligations of $162 million (year ended December 31, 2013 – $131 million) and recognized net deferred income tax assets of $91 million (year ended December 31, 2013 – $75 million) related to temporary differences in the carrying amount of certain of the acquired properties and their tax bases. No debt obligations were assumed. The Company recognized after-tax gains of $137 million (year ended December 31, 2013 – $65 million) on these acquisitions. The above amounts are estimates and may be subject to change based on the receipt of new information.

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 2014, pre-tax interest of $204 million (December 31, 2013 – $175 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (December 31, 2013 – 4.4%)

6. OTHER LONG-TERM ASSETS

	Dec 31 2014	Dec 31 2013
Investment in North West Redwater Partnership	**$ 298**	$ 306
North West Redwater Partnership subordinated debt [(1)]	**120**	–
Risk Management (note 14)	**599**	–
Other	**167**	136
	1,184	442
Less: current portion	**510**	–
	$ 674	$ 442

(1) Includes accrued interest.

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 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 2014, Redwater Partnership, the Company and APMC amended certain terms of the processing agreements. In conjunction with these amendments, in order to provide financing for Project completion based on the current revised Project cost estimate of approximately $8,500 million, the Company, along with APMC, each committed to provide additional funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2014, the Company and APMC each provided $113 million of subordinated debt. Subsequent to December 31, 2014, the Company and APMC each provided an additional $112 million of subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During 2014, Redwater Partnership executed a $3,500 million syndicated credit facility with a group of financial institutions maturing June 2018 and repaid and cancelled its $1,200 million credit facility previously in place. As at December 31, 2014, Redwater Partnership had borrowings of $913 million under the syndicated credit facility.

In addition, during 2014, Redwater Partnership issued $500 million of 3.20% series A senior secured bonds due July 2024 and $500 million of 4.05% series B senior secured bonds due July 2044. Subsequent to December 31, 2014, Redwater Partnership issued $500 million of 2.10% series C senior secured bonds due February 2022 and $500 million of 3.70% series D senior secured bonds due February 2043.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

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.

7. LONG-TERM DEBT

		Dec 31 2014		Dec 31 2013
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**2,404**	$	1,246
Medium-term notes		**2,400**		1,400
		4,804		2,646
US dollar denominated debt, unsecured				
Commercial paper (US$500 million)	**$**	**580**	$	532
US dollar debt securities (December 31, 2014 – US$7,500 million; December 31, 2013 – US$6,150 million)		**8,701**		6,541
Less: original issue discount on US dollar debt securities (1)		**(21)**		(18)
		9,260		7,055
Fair value impact of interest rate swaps on US dollar debt securities (2)		**–**		9
		9,260		7,064
Long-term debt before transaction costs		**14,064**		9,710
Less: transaction costs (1) (3)		**(62)**		(49)
		14,002		9,661
Less: current portion of commercial paper		**580**		532
current portion of long-term debt (1) (2) (3)		**400**		912
	$	**13,022**	$	8,217

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

(2) The carrying amount of US$350 million of 4.90% notes repaid December 2014 was adjusted by $9 million at December 31, 2013 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, 2014, the Company had in place bank credit facilities of $5,627 million available for general corporate purposes, comprised of:

- a $100 million demand credit facility;
- a $1,000 million non-revolving term credit facility maturing March 2016, subsequently extended to January 2017;
- a $1,500 million revolving syndicated credit facility maturing June 2016;
- a $3,000 million revolving syndicated credit facility maturing June 2017; and
- a £15 million demand credit facility related to the Company's North Sea operations.

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

Subsequent to December 31, 2014 the existing $1,000 million non-revolving term credit facility was extended and now matures January 2017. In addition the Company entered into a new $1,500 million non-revolving three-year term credit facility maturing April 2018. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

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

In connection with the agreement to acquire certain producing Canadian crude oil and natural gas properties (refer to note 5), the Company arranged a $1,000 million unsecured non-revolving bank credit facility. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at December 31, 2014, the Company had $1,000 million outstanding under this facility.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2014 was 2.2% (December 31, 2013 – 1.9%), and on long-term debt outstanding for the year ended December 31, 2014 was 3.9% (December 31, 2013 – 4.4%).

At December 31, 2014 letters of credit and financial guarantees aggregating $359 million, including a $39 million financial guarantee related to Horizon and $214 million of letters of credit related to North Sea operations, were outstanding. The letters of credit and financial guarantees are supported by dedicated credit facilities.

Medium-Term Notes

During the second quarter of 2014, the Company issued $500 million of 2.60% medium-term notes due December 2019 and $500 million of 3.55% medium-term notes due June 2024. After issuing these securities, the Company has $2,000 million remaining on its outstanding $3,000 million base shelf prospectus that allows for the issue of medium-term notes in Canada, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

During 2013, the Company repaid $400 million of 4.50% medium-term notes and issued $500 million of 2.89% medium-term notes due August 2020 under a previous base shelf prospectus.

US Dollar Debt Securities

During the first quarter of 2014, the Company issued US$500 million of three-month LIBOR plus 0.375% notes due March 2016, and concurrently entered into cross currency swaps to fix the foreign currency exchange rate risk at three-month CDOR plus 0.309% and $555 million (note 14). In addition, the Company issued US$500 million of 3.80% notes due April 2024.

During the fourth quarter of 2014, the Company issued US$600 million of 1.75% notes due January 2018, and US$600 million of 3.90% notes due February 2025.

After issuing these securities, the Company has US$800 million remaining on its outstanding US$3,000 million base shelf prospectus that allows for the issue of US dollar debt securities in the United States, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

During the year ended 2014, the Company repaid US$500 million of 1.45% notes and US$350 million of 4.90% notes (2013 – US$400 million of 5.15% notes).

8. OTHER LONG-TERM LIABILITIES

	Dec 31 2014	Dec 31 2013
Asset retirement obligations	**$ 4,221**	$ 4,162
Share-based compensation	**203**	260
Risk management (note 14)	**–**	136
Other	**70**	65
	4,494	4,623
Less: current portion	**319**	275
	$ 4,175	$ 4,348

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.6% (December 31, 2013 – 5.0%). A reconciliation of the discounted asset retirement obligations was as follows:

	Dec 31 2014	Dec 31 2013
Balance – beginning of year	**$ 4,162**	$ 4,266
Liabilities incurred	**41**	62
Liabilities acquired	**404**	131
Liabilities settled	**(346)**	(207)
Asset retirement obligation accretion	**193**	171
Revision of cost, inflation rates and timing estimates	**(907)**	375
Change in discount rate	**558**	(723)
Foreign exchange adjustments	**116**	87
Balance – end of year	**4,221**	4,162
Less: current portion	**121**	–
	$ 4,100	$ 4,162

Share-Based Compensation

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

	Dec 31 2014	Dec 31 2013
Balance – beginning of year	**$ 260**	$ 154
Share-based compensation expense	**66**	135
Cash payment for stock options surrendered	**(8)**	(4)
Transferred to common shares	**(129)**	(50)
Capitalized to Oil Sands Mining and Upgrading	**14**	25
Balance – end of year	**203**	260
Less: current portion	**158**	216
	$ 45	$ 44

9. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Year Ended	
	Dec 31 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Current corporate income tax – North America	**$ 123**	$ 133	**$ 702**	$ 544
Current corporate income tax – North Sea	**(23)**	5	**(68)**	23
Current corporate income tax – Offshore Africa [(1)]	**8**	55	**43**	202
Current PRT [(2)] (recovery) expense – North Sea	**(86)**	5	**(273)**	(56)
Other taxes	**5**	4	**23**	22
Current income tax expense	**27**	202	**427**	735
Deferred corporate income tax expense (recovery)	**254**	(36)	**681**	163
Deferred PRT [(2)] (recovery) expense – North Sea	**(1)**	(60)	**126**	(132)
Deferred income tax expense (recovery)	**253**	(96)	**807**	31
Income tax expense	**$ 280**	$ 106	**$ 1,234**	$ 766

(1) Includes current income taxes relating to disposition of properties in 2013.
(2) Petroleum Revenue Tax.

10. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Year Ended Dec 31, 2014		
Issued common shares	**Number of shares** (thousands)		**Amount**
Balance – beginning of year	**1,087,322**	**$**	**3,854**
Issued upon exercise of stock options	**14,610**		**488**
Previously recognized liability on stock options exercised for common shares	**–**		**129**
Purchase of common shares under Normal Course Issuer Bid	**(10,095)**		**(39)**
Balance – end of year	**1,091,837**	**$**	**4,432**

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 4, 2015, the Board of Directors approved the regular quarterly dividend at $0.23 per common share, an increase from the previous quarterly dividend of $0.225 per common share, which was approved on March 5, 2014.

Normal Course Issuer Bid

In April 2014, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the twelve month period commencing April 2014 and ending April 2015, up to 54,596,899 common shares. The Company's Normal Course Issuer Bid announced in 2013 expired April 2014.

For the year ended December 31, 2014, the Company purchased for cancellation 10,095,000 common shares at a weighted average price of $44.85 per common share, for a total cost of $453 million. Retained earnings were reduced by $414 million, representing the excess of the purchase price of common shares over their average carrying value.

Stock Options

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

	Year Ended Dec 31, 2014		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of year	**72,741**	**$**	**34.36**
Granted	**18,517**	**$**	**38.70**
Surrendered for cash settlement	**(1,047)**	**$**	**33.74**
Exercised for common shares	**(14,610)**	**$**	**33.40**
Forfeited	**(3,893)**	**$**	**36.00**
Outstanding – end of year	**71,708**	**$**	**35.60**
Exercisable – end of year	**23,717**	**$**	**36.27**

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 2014	Dec 31 2013
Derivative financial instruments designated as cash flow hedges	**$ 94**	$ 81
Foreign currency translation adjustment	**(43)**	(39)
	$ 51	$ 42

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, 2014, the ratio was within the target range at 33%.

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 2014	Dec 31 2013
Long-term debt [(1)]	**$ 14,002**	$ 9,661
Total shareholders' equity	**$ 28,891**	$ 25,772
Debt to book capitalization	**33%**	27%

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

13. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Weighted average common shares outstanding – basic (thousands of shares)	**1,091,427**	1,086,271	**1,091,754**	1,088,682
Effect of dilutive stock options (thousands of shares)	**3,054**	1,739	**5,068**	1,859
Weighted average common shares outstanding – diluted (thousands of shares)	**1,094,481**	1,088,010	**1,096,822**	1,090,541
Net earnings	**$ 1,198**	$ 413	**$ 3,929**	$ 2,270
Net earnings per common share – basic	**$ 1.10**	$ 0.38	**$ 3.60**	$ 2.08
– diluted	**$ 1.09**	$ 0.38	**$ 3.58**	$ 2.08

14. FINANCIAL INSTRUMENTS

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

	Dec 31, 2014				
Asset (liability)	**Financial assets at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,889**	**$ –**	**$ –**	**$ –**	**$ 1,889**
Other long-term assets	**120**	**415**	**184**	**–**	**719**
Accounts payable	**–**	**–**	**–**	**(564)**	**(564)**
Accrued liabilities	**–**	**–**	**–**	**(3,279)**	**(3,279)**
Other long-term liabilities	**–**	**–**	**–**	**(40)**	**(40)**
Long-term debt (1)	**–**	**–**	**–**	**(14,002)**	**(14,002)**
	$ 2,009	**$ 415**	**$ 184**	**$ (17,885)**	**$ (15,277)**

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

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

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

	2014			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3**
Other long-term assets (3)	**$ 719**	**$ –**	**$ 599**	**$ 120**
Fixed rate long-term debt (4) (5)	**(11,018)**	**(11,855)**	**–**	**–**
	$ (10,299)	**$ (11,855)**	**$ 599**	**$ 120**

	2013			
	Carrying amount	Fair value		
Asset (liability) (1) (2)		Level 1	Level 2	Level 3
Other long-term liabilities	$ (136)	$ –	$ (136)	$ –
Fixed rate long-term debt (4) (5) (6)	(7,883)	(8,628)	–	–
	$ (8,019)	$ (8,628)	$ (136)	$ –

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

(2) There were no transfers between Level 1, 2 and 3 financial instruments.

(3) The fair value of North West Redwater Partnership subordinated debt is based on the present value of future cash receipts.

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

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

(6) The carrying amount of US$350 million of 4.90% notes repaid December 2014 was adjusted by $9 million at December 31, 2013 to reflect the fair value impact of hedge accounting.

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, 2014	Dec 31, 2013
Derivatives held for trading		
Crude oil price collars	**$ 410**	$ (33)
Crude oil WCS [1] differential swaps	**(16)**	–
Foreign currency forward contracts	**21**	(3)
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	**11**	(1)
Cross currency swaps	**173**	(96)
	$ 599	$ (136)
Included within:		
Current portion of other long-term assets (liabilities)	**$ 436**	$ (38)
Other long-term assets (liabilities)	**163**	(98)
	$ 599	$ (136)

(1) Western Canadian Select.

During 2014, the Company recognized a loss of $3 million (December 31, 2013 – gain of $4 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 1 and Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

Risk Management

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

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

Asset (liability)	**Dec 31, 2014**	Dec 31, 2013
Balance – beginning of year	**$ (136)**	$ (257)
Cost of outstanding put options	**–**	9
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	**451**	(39)
Foreign exchange	**270**	165
Other comprehensive income	**14**	(5)
	599	(127)
Add: put premium financing obligations (1)	**–**	(9)
Balance – end of year	**599**	(136)
Less: current portion	**436**	(38)
	$ 163	$ (98)

(1) The Company 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 2013 risk management liability.

Net gains from risk management activities were as follows:

	Three Months Ended		Year Ended	
	Dec 31 2014	Dec 31 2013	**Dec 31 2014**	Dec 31 2013
Net realized risk management gain	**$ (335)**	$ (36)	**$ (349)**	$ (116)
Net unrealized risk management (gain) loss	**(404)**	(30)	**(451)**	39
	$ (739)	$ (66)	**$ (800)**	$ (77)

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, 2014, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Price collars	Jan 2015 – Dec 2015	50,000 bbl/d	US$80.00 – US$120.52	Brent
WCS differential swaps	Jan 2015 – Mar 2015	30,000 bbl/d	US$21.49	WCS

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, 2014, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At December 31, 2014, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Jan 2015	–	Mar 2016	US$500	1.109	Three-month LIBOR plus 0.375%	Three-month CDOR (1) plus 0.309%
	Jan 2015	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2015	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2015	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2015	–	Mar 2038	US$550	1.170	6.25%	5.76%

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

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

In addition to the cross currency swap contracts noted above, at December 31, 2014, the Company had US$1,766 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, 2014, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2014, the Company had net risk management assets of $622 million with specific counterparties related to derivative financial instruments (December 31, 2013 – $nil).

c) Liquidity risk

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

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

The maturity dates for financial liabilities were as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	564	$	–	$	–	$	–
Accrued liabilities	$	3,279	$	–	$	–	$	–
Other long-term liabilities	$	40	$	–	$	–	$	–
Long-term debt (1)	$	980	$	2,397	$	4,313	$	6,395

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

15. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

		2015		2016		2017		2018		2019		Thereafter
Product transportation and pipeline	$	442	$	334	$	301	$	268	$	237	$	1,512
Offshore equipment operating leases and offshore drilling	$	341	$	92	$	66	$	59	$	19	$	–
Office leases	$	42	$	42	$	44	$	46	$	47	$	284
Other	$	204	$	125	$	40	$	1	$	–	$	–

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

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

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	
	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013	2014	2013
Segmented product sales	3,586	2,833	15,963	12,659	205	229	701	805	111	335	503	824	3,902	3,397	17,167	14,288
Less: royalties	(407)	(281)	(2,159)	(1,477)	–	–	(2)	(2)	(8)	(52)	(43)	(137)	(415)	(333)	(2,204)	(1,616)
Segmented revenue	3,179	2,552	13,804	11,182	205	229	699	803	103	283	460	687	3,487	3,064	14,963	12,672
Segmented expenses																
Production	754	578	2,924	2,351	171	134	496	431	74	91	212	191	999	803	3,632	2,973
Transportation and blending	757	647	3,228	2,939	2	2	5	6	–	–	1	1	759	649	3,234	2,946
Depletion, depreciation and amortization	1,059	905	3,901	3,568	120	184	269	552	31	44	105	134	1,210	1,133	4,275	4,254
Asset retirement obligation accretion	25	23	98	92	10	9	38	35	2	6	10	10	37	38	146	137
Realized risk management activities	(335)	(36)	(349)	(116)	–	–	–	–	–	–	–	–	(335)	(36)	(349)	(116)
Gain on corporate acquisitions/disposition of properties	(137)	–	(137)	(65)	–	–	–	–	–	–	–	(224)	(137)	–	(137)	(289)
Equity loss from investment	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total segmented expenses	2,123	2,117	9,665	8,769	303	329	808	1,024	107	141	328	112	2,533	2,587	10,801	9,905
Segmented earnings (loss) before the following	1,056	435	4,139	2,413	(98)	(100)	(109)	(221)	(4)	142	132	575	954	477	4,162	2,767
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Unrealized risk management activities																
Foreign exchange loss																
Total non-segmented expenses																
Earnings before taxes																
Current income tax expense																
Deferred income tax expense (recovery)																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				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	
	2014	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Segmented product sales	**932**	915	**4,095**	3,631	**29**	26	**120**	110	**(13)**	(8)	**(81)**	(84)	**4,850**	4,330	**21,301**	17,945
Less: royalties	**(51)**	(50)	**(234)**	(184)	**–**	–	**–**	–	**–**	–	**–**	–	**(466)**	(383)	**(2,438)**	(1,800)
Segmented revenue	**881**	865	**3,861**	3,447	**29**	26	**120**	110	**(13)**	(8)	**(81)**	(84)	**4,384**	3,947	**18,863**	16,145
Segmented expenses																
Production	**395**	389	**1,609**	1,567	**7**	8	**34**	34	**(2)**	(2)	**(10)**	(15)	**1,399**	1,198	**5,265**	4,559
Transportation and blending	**20**	15	**75**	63	**–**	–	**–**	–	**(20)**	(19)	**(77)**	(71)	**759**	645	**3,232**	2,938
Depletion, depreciation and amortization	**194**	137	**596**	582	**2**	2	**9**	8	**–**	–	**–**	–	**1,406**	1,272	**4,880**	4,844
Asset retirement obligation accretion	**12**	8	**47**	34	**–**	–	**–**	–	**–**	–	**–**	–	**49**	46	**193**	171
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(335)**	(36)	**(349)**	(116)
Gain on corporate acquisitions/disposition of properties	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(137)**	–	**(137)**	(289)
Equity loss from investment	**–**	–	**–**	–	**5**	1	**8**	4	**–**	–	**–**	–	**5**	1	**8**	4
Total segmented expenses	**621**	549	**2,327**	2,246	**14**	11	**51**	46	**(22)**	(21)	**(87)**	(86)	**3,146**	3,126	**13,092**	12,111
Segmented earnings (loss) before the following	**260**	316	**1,534**	1,201	**15**	15	**69**	64	**9**	13	**6**	2	**1,238**	821	**5,771**	4,034
Non-segmented expenses																
Administration													**100**	93	**367**	335
Share-based compensation													**(144)**	65	**66**	135
Interest and other financing expense													**84**	60	**323**	279
Unrealized risk management activities													**(404)**	(30)	**(451)**	39
Foreign exchange loss													**124**	114	**303**	210
Total non-segmented expenses													**(240)**	302	**608**	998
Earnings before taxes													**1,478**	519	**5,163**	3,036
Current income tax expense													**27**	202	**427**	735
Deferred income tax expense (recovery)													**253**	(96)	**807**	31
Net earnings													**1,198**	413	**3,929**	2,270

Capital Expenditures [1]

	Year Ended					
	Dec 31, 2014			Dec 31, 2013		
	Net expenditures	**Non-cash and fair value changes**[2]	**Capitalized costs**	Net expenditures	Non-cash and fair value changes[2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ 1,103**	**$ (247)**	**$ 856**	$ 90	$ (84)	$ 6
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa [3]	**87**	**–**	**87**	(10)	–	(10)
	$ 1,190	**$ (247)**	**$ 943**	$ 80	$ (84)	$ (4)
Property, plant and equipment						
Exploration and Production						
North America	**$ 6,397**	**$ 399**	**$ 6,796**	$ 3,936	$ (450)	$ 3,486
North Sea	**400**	**86**	**486**	334	(35)	299
Offshore Africa	**194**	**(1)**	**193**	114	(17)	97
	6,991	**484**	**7,475**	4,384	(502)	3,882
Oil Sands Mining and Upgrading [4]	**3,110**	**(528)**	**2,582**	2,592	(189)	2,403
Midstream	**62**	**–**	**62**	197	(1)	196
Head office	**45**	**(1)**	**44**	38	–	38
	$ 10,208	**$ (45)**	**$ 10,163**	$ 7,211	$ (692)	$ 6,519

(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 in 2013 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 its 50% interest in its exploration right in South Africa.

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

Segmented Assets

	Total Assets	
	Dec 31 2014	Dec 31 2013
Exploration and Production		
North America	**$ 34,382**	$ 29,234
North Sea	**2,711**	1,964
Offshore Africa	**1,214**	981
Other	**18**	25
Oil Sands Mining and Upgrading	**20,702**	18,604
Midstream	**1,048**	841
Head office	**125**	105
	$ 60,200	$ 51,754

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated November 2013. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended December 31, 2014:

Interest coverage (times)	
Net earnings (1)	10.6x
Cash flow from operations (2)	20.1x

(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 5, 2015. The North American conference call number is 1-877-223-4471 and the outside North American conference call number is 001-647-788-4922. Please call in about 10 minutes before the starting time in order to be patched into the call.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Thursday, March 12, 2014. To access the rebroadcast in North America, dial 1-800-585-8367. Those outside of North America, dial 001-416-621-4642. The conference ID number to use is 51986462.

WEBCAST

This call is being webcast and can be accessed on Canadian Natural's website at www.cnrl.com. Presentation slides will be available on Canadian Natural's website in PDF format shortly before the live conference call webcast.

For further information, please contact:

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