Canadian Natural

FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2015 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2015 FIRST QUARTER RESULTS

Commenting on first quarter results, Steve Laut, President of Canadian Natural stated, “As expected, low commodity prices impacted first quarter cash flow and earnings. Operationally, the first quarter was very strong with record quarterly production approaching 900,000 BOE/d. Crude oil production increased by 23% and natural gas production increased by 51% from the first quarter of 2014. Canadian Natural’s operations continue to be effective and efficient as operating costs reduced by 22% for total liquids and 10% for North America natural gas in the first quarter of 2015 versus the same quarter in 2014. Our performance reflects the resilience of our strong, diverse and well balanced asset base, the robustness of our business model, and the effectiveness of our strategies combined with our ability to execute these strategies.”

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “Canadian Natural continues to prudently manage its balance sheet and liquidity. Following the precipitous fall in crude oil pricing, we proactively adjusted our capital spending profile to reflect targeted internal cash flow generation while optimizing the value of investments made and protecting the growth profile of the Horizon Project. We continue to focus on cost reduction and efficiency improvements to further improve returns in the current price environment. Our balance sheet metrics remain strong, giving us the financial flexibility to deliver our defined growth plan and continue to drive long-term shareholder value creation irrespective of the business cycle.”

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended Mar 31 2015	Dec 31 2014	Mar 31 2014
Net earnings (loss)	**$ (252)**	$ 1,198	$ 622
Per common share – basic	**$ (0.23)**	$ 1.10	$ 0.57
– diluted	**$ (0.23)**	$ 1.09	$ 0.57
Adjusted net earnings from operations (1)	**$ 21**	$ 756	$ 921
Per common share – basic	**$ 0.02**	$ 0.69	$ 0.85
– diluted	**$ 0.02**	$ 0.69	$ 0.85
Cash flow from operations (2)	**$ 1,370**	$ 2,368	$ 2,146
Per common share – basic	**$ 1.25**	$ 2.17	$ 1.97
– diluted	**$ 1.25**	$ 2.16	$ 1.97
Capital expenditures, net of dispositions	**$ 1,412**	$ 2,220	$ 1,893
Daily production, before royalties			
Natural gas (MMcf/d)	**1,771**	1,733	1,175
Crude oil and NGLs (bbl/d)	**602,809**	572,040	488,788
Equivalent production (BOE/d) (3)	**898,053**	860,920	684,647

(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.

- Strong operational performance continues for all business segments of the Company. Canadian Natural's Exploration and Production ("E&P") assets continue to generate free cash flow and support the transition to a longer life and lower decline asset base. Q1/15 operational highlights include:
  - Record overall quarterly corporate production of 898,053 BOE/d driven by records in both quarterly crude oil and NGL, and natural gas production volumes.
  - Corporate quarterly crude oil and NGL production reached record levels averaging 602,809 bbl/d for Q1/15, an increase of 23% and 5% from Q1/14 and Q4/14 levels respectively.
    - The Company's E&P crude oil and NGL segment showed strong overall production volumes driven by:
      a. Record North America light crude oil and NGL quarterly production volumes of 97,561 bbl/d.
      b. Record thermal in situ oil sands ("thermal") quarterly production performance of 146,086 bbl/d.
      c. Strong primary heavy crude oil production volumes of 137,687 bbl/d.
      d. Strong Pelican Lake quarterly production volumes of 51,085 bbl/d.
      e. International quarterly production volumes of 36,224 bbl/d.
    - Record quarterly production volumes of 134,166 bbl/d were achieved at Horizon Oil Sands ("Horizon").
  - Natural gas production achieved record quarterly volumes averaging 1,771 MMcf/d in Q1/15, an increase of 51% and 2% from Q1/14 and Q4/14 levels respectively.

- Canadian Natural's 2015 capital expenditure guidance has been updated to reflect capital cost savings across all business segments. The Company's targeted 2015 capital expenditure guidance has been reduced further by approximately $300 million, as compared to capital guidance released in March 2015, to approximately $5.7 billion. Annual production guidance remains unchanged and is targeted to deliver 11% annual production growth in 2015 over 2014 levels.
- Canadian Natural targets to achieve approximately $390 million of additional operating costs savings in 2015 in comparison to the 2015 original budgeted operating cost targets announced in November 2014. In comparison to 2014, these savings plus the initiatives underway through effective and efficient operations, innovation initiatives, reduced energy costs and higher production volumes result in 2015 operating costs being approximately $925 million less than what they would have been at 2014 unit cost rates.
  - Overall corporate crude oil and NGL operating costs of $19.03/bbl in Q1/15 decreased by $5.33/bbl and $3.01/bbl from Q1/14 and Q4/14 levels, respectively.
    a. In Q1/15, North America E&P (including thermal) crude oil and NGL quarterly operating costs were $13.75/bbl, which decreased by 16% and 4% from Q1/14 and Q4/14 levels respectively. Annual operating cost guidance is targeted to range from $12.50/bbl to $14.50/bbl.
    b. Horizon quarterly operating costs showed significant improvement at $29.73/bbl in Q1/15, with decreases of 28% from $41.11/bbl in Q1/14 and 13% from $34.34/bbl in Q4/14. The annual operating cost guidance has been reduced and is targeted to range from $31.00/bbl to $34.00/bbl in 2015. Strong operating costs reflect safe, steady, reliable production and improved operating efficiencies.
  - In Q1/15, North America natural gas operating costs were $1.38/Mcf, a 10% decrease from Q1/14 levels of $1.54/Mcf, reflecting a continued focus on cost optimization after acquiring higher cost production volumes in 2014. In 2015, the Company will continue its strong, effective and efficient operations with a focus on cost optimization. As a result, annual operating cost guidance has been reduced and is targeted to range from $1.25/Mcf to $1.35/Mcf.
- Canadian Natural generated cash flow from operations of approximately $1.4 billion in Q1/15 compared to approximately $2.1 billion in Q1/14 and $2.4 billion in Q4/14. The decrease in Q1/15 from Q1/14 and Q4/14 primarily reflects lower crude oil, NGL and natural gas realized pricing in North America, lower synthetic crude oil ("SCO") realized pricing, partially offset by higher North America crude oil and NGL and SCO sales volumes and the impact of a weaker Canadian dollar as compared to the US dollar.
- The Company incurred a net loss in Q1/15 of $252 million, compared to net earnings of $622 million in Q1/14 and $1,198 million in Q4/14. Adjusted net earnings from operations for Q1/15 were $21 million, compared to adjusted net earnings of $921 million in Q1/14 and $756 million in Q4/14. Changes in net earnings and adjusted net earnings largely reflect the changes in cash flow.
- 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. Q4/14 production volumes on the royalty lands increased 3% and 14% from Q3/14 and Q2/14 levels respectively. Drilling activity has been strong on the Company's royalty lands with 144 wells drilled in Q4/14 and 75 wells drilled in Q1/15.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.23 per share payable on July 1, 2015.

CORPORATE UPDATE

Dr. Eldon Smith, due to reaching the mandatory retirement age, and Mr. Keith A.J. MacPhail, due to a desire to free up more time for personal interests, have chosen to not stand for re-election to the Company's Board of Directors in 2015. The Board of Directors and the Senior Management of Canadian Natural wish to thank Dr. Smith and Mr. MacPhail for their service and for their contributions over the years to the success of the Company.

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

	Three Months Ended Mar 31			
	2015		2014	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**48**	**42**	300	271
Natural gas	**13**	**9**	32	25
Dry	**2**	**2**	4	3
Subtotal	**63**	**53**	336	299
Stratigraphic test / service wells	**121**	**86**	330	330
Total	**184**	**139**	666	629
Success rate (excluding stratigraphic test / service wells)		**96%**		99%

- As a direct result of the downturn in crude oil and natural gas pricing commencing in the second half of 2014, the Company reduced its 2015 drilling programs. Drilling activity in Q1/15 consisted of 139 net wells compared to 629 net wells in Q1/14.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Crude oil and NGLs production (bbl/d)	**286,333**	291,002	266,110
Net wells targeting crude oil	**40**	332	263
Net successful wells drilled	**38**	324	260
Success rate	**95%**	98%	99%

- North America crude oil and NGLs achieved quarterly production of 286,333 bbl/d in Q1/15, an increase of 8% from Q1/14 levels and a slight decrease of 2% from Q4/14 levels.
- North America light crude oil and NGLs achieved record quarterly production averaging 97,561 bbl/d in Q1/15. Production increased 29% and 2% from Q1/14 levels and Q4/14 levels respectively, largely as a result of the successful integration of light crude oil and NGL production volumes acquired in 2014, complemented by a successful drilling program.
- As expected, Pelican Lake operations achieved solid quarterly heavy crude oil production volumes of 51,085 bbl/d, a 6% increase from Q1/14 levels and comparable to Q4/14 levels. Canadian Natural continues to achieve success in developing, implementing and optimizing the leading edge polymer flood technology at Pelican Lake.

- In Q1/15, primary heavy crude oil production averaged 137,687 bbl/d, a decrease of 3% and 5% from Q1/14 and Q4/14 levels respectively. The decrease in production volumes reflects a reduced drilling program, as a result of a prudent reduction in capital allocation due to unfavorable commodity pricing and economic conditions. The Company's high working interest, large undeveloped land base of over 8,000 potential well locations and extensive operated infrastructure enable Canadian Natural to exercise a nimble, flexible capital allocation program. Canadian Natural drilled 36 net primary heavy crude oil wells in Q1/15 compared to 224 and 305 net primary heavy crude oil wells drilled in Q1/14 and Q4/14 respectively.

Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Bitumen production (bbl/d)	**146,086**	118,974	82,077
Net wells targeting bitumen	**3**	–	11
Net successful wells drilled	**3**	–	11
Success rate	**100%**	–	100%

- In Q1/15, record thermal in situ quarterly production volumes were achieved averaging 146,086 bbl/d, an increase of 78% and 23% from Q1/14 and Q4/14 production volumes respectively. The increase in Q1/15 from Q1/14 reflects record production volumes at Primrose and increased Kirby South production volumes.
- Primrose production volumes reached record quarterly average levels of 122,386 bbl/d in Q1/15, resulting from the Company's execution excellence in optimizing operations and reflecting the cyclic nature of the operations. As expected, Q2/15 total thermal production volumes are targeted to range from 106,000 bbl/d to 115,000 bbl/d.
- Subsequent to Q1/15, Canadian Natural submitted its Primrose Flow-to-Surface ("FTS") Final Report. The report reflects the Company's initial findings as reported in its Primrose FTS Causation Report submitted in early 2014.
- The Company commenced a low pressure steamflood at Primrose East Area 1 in September 2014. Production ramp up is meeting expectations with current volumes of approximately 11,000 bbl/d. Additionally, low pressure cyclic steam stimulation ("CSS") operations at Primrose East Area 2 received regulatory approval and steaming was subsequently implemented in February 2015 with production ramping up as expected.
- At Kirby South, Q1/15 production volumes increased to 23,700 bbl/d as operations continue to ramp up to the targeted 40,000 bbl/d of design capacity. The reservoir continues to perform as expected with very good thermal efficiencies. For wells on Steam Assisted Gravity Drainage ("SAGD"), steam to oil ratio ("SOR") in Q1/15 was 2.4. For April 2015, Kirby South's production continues to ramp up to volumes averaging approximately 27,500 bbl/d.

Natural Gas

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Natural gas production (MMcf/d)	**1,713**	1,705	1,147
Net wells targeting natural gas	**9**	16	25
Net successful wells drilled	**9**	16	25
Success rate	**100%**	100%	100%

- North America natural gas production reached record quarterly levels averaging 1,713 MMcf/d for Q1/15, an increase of 49% from Q1/14 and comparable to Q4/14 levels. The increase from Q1/14 levels resulted from additional production volumes acquired in 2014, complemented by a focused liquids-rich natural gas drilling program.

- North America natural gas quarterly operating costs were $1.38/Mcf in Q1/15, a 10% decrease from Q1/14 levels of $1.54/Mcf, reflecting a continued focus on cost optimization after acquiring higher cost production volumes in 2014. In 2015, the Company will continue its strong, effective and efficient operations with a focus on cost optimization. As a result, annual operating cost guidance has been reduced and is targeted to range from $1.25/Mcf to $1.35/Mcf.

International Exploration and Production

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Crude oil production (bbl/d)			
North Sea	**23,036**	21,927	16,715
Offshore Africa	**13,188**	12,047	10,791
Natural gas production (MMcf/d)			
North Sea	**34**	10	7
Offshore Africa	**24**	18	21
Net wells targeting crude oil	**0.6**	1.0	–
Net successful wells drilled	**0.6**	1.0	–
Success rate	**100%**	100%	–

- International crude oil production averaged 36,224 bbl/d during Q1/15, an increase of 32% from Q1/14 levels and a 7% increase from Q4/14 levels. The increase in production over Q1/14 levels was primarily due to the reinstatement of the Banff/Kyle Floating Production Storage and Offtake Vessel (“FPSO”) in July 2014 and increased production from Baobab after experiencing downtime in Q1/14. Q1/15 production volumes also reflect the return to production on the Tiffany platform which experienced unplanned downtime during Q4/14, and higher production at Espoir.
- In offshore Côte d’Ivoire, 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. In Q1/15, the first oil well was brought on stream and is currently producing at a net rate of approximately 3,000 bbl/d. In April 2015, the Company commenced production from its second well at a net production rate of approximately 2,100 bbl/d. Production from both wells is above expectations and the program is progressing below budget and on schedule.
- The Company has also 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 June 2015.
- 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. In April 2015, a second exploration well was drilled to evaluate the up-dip potential of the initial well. The well has been plugged and abandoned, and the results will be evaluated and integrated into our understanding of the block.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Synthetic crude oil production (bbl/d) (1)	**134,166**	128,090	113,095

(1) The Company has commenced production of diesel for internal use at Horizon. First quarter 2015 SCO production before royalties excludes 1,676 bbl/d of SCO consumed internally as diesel (fourth quarter 2014 – 1,288 bbl/d; first quarter 2014 – nil).

- Horizon achieved record quarterly production of 134,166 bbl/d of SCO, an increase of 19% from Q1/14 levels and an increase of 5% from Q4/14 levels. As previously discussed in Canadian Natural's Q4/14 and Year End Results, new equipment performance and the execution of an optimized mining strategy have increased the stability of the extraction and upgrading processes, resulting in increased nameplate capacity to 137,000 bbl/d. Horizon productive capacity reflects target utilization rates ranging from 92% to 96% of the plant nameplate capacity. During Q1/15, utilization rates were exceptional reaching 98%. April 2015 average production volumes at Horizon were approximately 123,000 bbl/d, slightly below the target utilization rate range. Annual production guidance range remains between 121,000 bbl/d and 131,000 bbl/d.
- Strong quarterly operating costs at Horizon averaged $29.73/bbl in Q1/15, representing a decrease of 28% from $41.11/bbl in Q1/14 and a decrease of 13% from $34.34/bbl in Q4/14. Decreases in operating costs reflect safe, steady and reliable operations, the impact of cost reduction initiatives across the site, the production and internal use of mine diesel, lower energy costs, and higher production volumes on a relatively fixed cost structure. As a result of these factors, Horizon's 2015 operating cost guidance range has been reduced to $31.00/bbl to $34.00/bbl. As production volumes increase with the expansion to 250,000 bbl/d, which is targeted for completion at the end of 2017, production costs are targeted to reduce further, ranging between $25.00/bbl and $27.00/bbl.
- The 2015 maintenance turnaround targeted for this fall has been accelerated to June 2015. Along with performing critical maintenance activities of the plant, the Horizon team will also take advantage of the opportunity to enhance reliability, optimize vessel performance and potentially increase capacity of the Diluent Recovery Unit ("DRU").
- 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 ahead of schedule. Compared to the Company's original 2015 budget released in November 2014, $300 million is targeted to be reduced in 2015 on Horizon Phase 2/3 Expansion activities, with no impact to the current targeted schedule. Canadian Natural has committed to approximately 77% of the Engineering, Procurement and Construction contracts with over 72% of the construction contracts awarded to date, 85% being lump sum, ensuring greater cost certainty and efficiency.
- Overall Horizon Phase 2/3 expansion is 60% physically complete as at Q1/15:
  - Reliability – Tranche 2 is 100% physically complete. Completion occurred in 2014 resulting in increased performance and overall production reliability. This 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 53% 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. Through the completion of Phase 2A, additional coker capacity and equipment were added, increasing the plant nameplate 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 nameplate capacity to 137,000 bbl/d.
  - Phase 2B is 54% physically complete. This Phase expands the capacity of major components such as gas/oil hydrotreatment, froth treatment and the hydrogen plant. Due to continued strong construction performance on the Horizon expansion, certain components of this project will be tied-in during the May 2016 turnaround. 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 planned production ramp up. 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 51% 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.

ROYALTY PRODUCTION AND REVENUE

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 Q4/14:

- The development of leased acreage is ongoing and lease requests on undeveloped acreage continue to be evaluated. Q4/14 production volumes on the royalty lands increased 3% and 14% from Q3/14 and Q2/14 levels respectively. Drilling activity has been strong on the Company's royalty lands with 144 wells drilled in Q4/14, of which 127 wells were drilled by third parties and 17 wells were drilled by Canadian Natural. In Q1/15, drilling activity consisted of 75 wells drilled, 72 wells were drilled by third parties and 3 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 below 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.

Royalty Production Volumes Comparison (1)

	Q4/14	Q3/14
Natural gas (MMcf/d)	24.0	23.6
Crude oil (bbl/d)	4,203	4,047
NGLs (bbl/d)	534	472
Total (BOE/d)	**8,732**	**8,448**

Royalty Production Volumes (1)

	Royalty volumes for Q4/14 attributable to		
	Third Party	Canadian Natural (2)	Total
Natural gas (MMcf/d)	20.6	3.4	24.0
Crude oil (bbl/d)	3,513	690	4,203
NGLs (bbl/d)	491	43	534
Total (BOE/d)	**7,442**	**1,290**	**8,732**

Royalty Revenue by Product (1)

($ millions)	Royalty revenue for Q4/14 attributable to Third Party	Canadian Natural (2)	Total
Natural gas	$ 7	$ 1	$ 8
Crude oil	$ 22	$ 4	$ 26
NGLs	$ 2	$ -	$ 2
Other revenue (3)	$ 4	$ -	$ 4
Total	**$ 35**	**$ 5**	**$ 40**

Revenue by Royalty Classification (1)

($ millions)	Royalty revenue for Q4/14 attributable to Third Party	Canadian Natural (2)	Total
Fee title	$ 19	$ 4	$ 23
Gross overriding royalty (4)	$ 12	$ 1	$ 13
Other revenue (3)	$ 4	$ -	$ 4
Total	**$ 35**	**$ 5**	**$ 40**

Royalty Realized Pricing (1)

	Q4/14
Natural gas ($/Mcf)	$ 3.60
Crude oil ($/bbl)	$ 67.84
NGLs ($/bbl)	$ 41.15
Total ($/BOE)	**$ 50.35**

Royalty Acreage

(gross acres, millions)	Leased to Third Party and Unleased	Canadian Natural (2)	Total
Fee title (5)	3.14	0.21	3.35
Gross overriding royalty (4)	1.90	1.64	3.54
Total	**5.04**	**1.85**	**6.89**

(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.

MARKETING

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Crude oil and NGLs pricing			
WTI benchmark price (US$/bbl) [1]	**$ 48.57**	$ 73.12	$ 98.61
WCS blend differential from WTI (%) [2]	**30%**	20%	24%
SCO price (US$/bbl)	**$ 45.26**	$ 71.01	$ 96.45
Condensate benchmark pricing (US$/bbl)	**$ 45.59**	$ 70.54	$ 102.53
Average realized pricing before risk management (C$/bbl) [3]	**$ 37.03**	$ 62.80	$ 79.68
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 2.80**	$ 3.80	$ 4.52
Average realized pricing before risk management (C$/Mcf)	**$ 3.38**	$ 4.32	$ 5.69

(1) West Texas Intermediate ("WTI").

(2) Western Canadian Select ("WCS").

(3) Average crude oil and NGL pricing excludes SCO. Pricing is net of blending costs and excluding risk management activities.

Benchmark Pricing	**WTI Pricing (US$/bbl)**	**WCS Blend Differential from WTI (%)**	**WCS Blend Differential from WTI (US$/bbl)**	**SCO Differential from WTI (US$/bbl)**	**Dated Brent Differential from WTI (US$/bbl)**	**Condensate Differential from WTI (US$/bbl)**
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	$ 47.85	27%	$ (13.09)	$ (3.33)	$ 7.94	$ 0.09
April	$ 54.63	26%	$ (14.37)	$ 0.86	$ 5.13	$ 0.68
May*	$ 60.65	20%	$ (11.87)	$ 3.43	$ 5.95	$ 1.54
June*	$ 61.67	14%	$ (8.73)	$ 3.68	$ 5.77	$ (1.37)

Based on current indicative pricing as at May 5, 2015.

- Volatility in supply and demand factors and geopolitical events continued to affect WTI and Brent 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 put downward pressure on benchmark pricing. Additionally, the growth of North American shale oil production continues to contribute to this downturn in benchmark pricing.
- The WCS differential to WTI averaged US$14.75/bbl or 30% in Q1/15 compared to US$23.27/bbl or 24% in Q1/14. The WCS heavy differential widened during Q1/15 compared to Q1/14 due to the rapid decline in WTI benchmark pricing. May 2015 and June 2015 indications of the WCS heavy differential are trending lower to US$11.87/bbl or 20% and US$8.73/bbl or 14%, respectively. Seasonal demand fluctuations, changes in transportation logistics and refinery utilization and shutdowns will continue to be reflected in WCS pricing.
- Canadian Natural contributed approximately 179,000 bbl/d of its heavy crude oil stream to the WCS blend in Q1/15. The Company remains the largest contributor to the WCS blend, accounting for 54% of the total blend.
- SCO pricing averaged US$45.26/bbl during Q1/15, a decrease of 53% from Q1/14 pricing of US$96.45/bbl and a decrease of 36% from US$71.01/bbl in Q4/14, primarily due to a decrease in WTI benchmark pricing.
- AECO natural gas pricing in Q1/15 averaged $2.80/GJ, a decrease of 38% and 26% from Q1/14 and Q4/14 pricing respectively.

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 898,100 BOE/d for Q1/15 with approximately 98% of production located in G8 countries.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 36% and debt to EBITDA of 1.7x at March 31, 2015.
- Canadian Natural maintains significant financial stability and liquidity represented in part by bank credit facilities. As at March 31, 2015, the Company had in place bank credit facilities of $7,128 million, of which $3,269 million was available.
- In March 2015, the United Kingdom ("UK") government enacted a reduction in the corporate tax rate charged on profits from North Sea oil and gas production from 62% to 50%, effective January 1, 2015 and a reduction in the rate of Petroleum Revenue Tax ("PRT") from 50% to 35%, effective January 1, 2016. This resulted in a decrease to the overall effective corporate tax rate applicable to net operating income from oil and gas activities to 50% for non-PRT paying fields, 75% for PRT paying fields effective January 1, 2015, and a further reduction to 67.5% for PRT paying fields effective January 1, 2016, after allowing for deductions for capital and abandonment expenditures. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes are still recoverable at the previous tax rate of 50%. As a result of the income tax rate changes, the Company's deferred income tax liability was decreased by $228 million. In addition, the UK government announced a new Investment Allowance replacing existing field allowances including Brown Field Allowance.
- 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.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.23 per share payable on July 1, 2015.
- Subsequent to Q1/15, Toronto Stock Exchange accepted notice of Canadian Natural's Normal Course Issuer Bid ("NCIB") through facilities of Toronto Stock Exchange and the New York Stock Exchange. The notice provides that Canadian Natural may, during the 12 month period commencing April 2015 and ending April 2016, purchase for cancellation on Toronto Stock Exchange and the New York Stock Exchange up to 54,640,607 common shares.
  - In 2015, the Company has not purchased any common shares under its NCIBs.
- 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. Q2/15 production guidance before royalties is forecast to average between 513,000 and 540,000 bbl/d of crude oil and NGLs and between 1,750 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.

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 ended March 31, 2015 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2014.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the period ended March 31, 2015 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 ended March 31, 2015 in relation to the first quarter of 2014 and the fourth 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, 2014, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated May 6, 2015.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Product sales	**$ 3,226**	$ 4,850	$ 4,968
Net earnings (loss)	**$ (252)**	$ 1,198	$ 622
Per common share – basic	**$ (0.23)**	$ 1.10	$ 0.57
– diluted	**$ (0.23)**	$ 1.09	$ 0.57
Adjusted net earnings from operations (1)	**$ 21**	$ 756	$ 921
Per common share – basic	**$ 0.02**	$ 0.69	$ 0.85
– diluted	**$ 0.02**	$ 0.69	$ 0.85
Cash flow from operations (2)	**$ 1,370**	$ 2,368	$ 2,146
Per common share – basic	**$ 1.25**	$ 2.17	$ 1.97
– diluted	**$ 1.25**	$ 2.16	$ 1.97
Capital expenditures, net of dispositions	**$ 1,412**	$ 2,220	$ 1,893

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

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

Adjusted Net Earnings from Operations

	Three Months Ended		
($ millions)	***Mar 31 2015***	*Dec 31 2014*	*Mar 31 2014*
Net earnings (loss) as reported	***$ (252)***	*$ 1,198*	*$ 622*
Share-based compensation, net of tax (1)	***64***	*(144)*	*143*
Unrealized risk management loss (gain), net of tax (2)	***9***	*(303)*	*38*
Unrealized foreign exchange loss, net of tax (3)	***413***	*106*	*118*
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	***–***	*36*	*–*
Equity loss from investment, net of tax (5)	***15***	*–*	*–*
Gain on corporate acquisition, net of tax (6)	***–***	*(137)*	*–*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (7)	***(228)***	*–*	*–*
Adjusted net earnings from operations	***$ 21***	*$ 756*	*$ 921*

(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, and foreign exchange.

(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.

(5) The Company's investment in the 50% owned North West Redwater Partnership is accounted for using the equity method of accounting. The non-cash equity loss from investment represents the Company's pro rata share of the North West Redwater Partnership's accounting loss.

(6) 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.

(7) During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and the Petroleum Revenue Tax ("PRT"), and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in deferred income tax liabilities of approximately $228 million.

Cash Flow from Operations

($ millions)	Three Months Ended Mar 31 2015	Dec 31 2014	Mar 31 2014
Net earnings (loss)	**$ (252)**	$ 1,198	$ 622
Non-cash items:			
Depletion, depreciation and amortization	**1,355**	1,406	1,011
Share-based compensation	**64**	(144)	143
Asset retirement obligation accretion	**43**	49	45
Unrealized risk management loss (gain)	**14**	(404)	49
Unrealized foreign exchange loss	**413**	106	118
Realized foreign exchange loss on repayment of US dollar debt securities	**–**	36	–
Equity loss from investment	**15**	5	1
Deferred income tax (recovery) expense	**(282)**	253	157
Gain on corporate acquisition	**–**	(137)	–
Cash flow from operations	**$ 1,370**	$ 2,368	$ 2,146

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net loss for the first quarter of 2015 was $252 million compared with net earnings of $622 million for the first quarter of 2014 and net earnings of $1,198 million for the fourth quarter of 2014. Net loss for the first quarter of 2015 included net after-tax expense of $273 million compared with $299 million for the first quarter of 2014 and net after-tax income of $442 million for the fourth 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, the gain on corporate acquisition, 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 first quarter of 2015 were $21 million compared with $921 million for the first quarter of 2014 and $756 million for the fourth quarter of 2014.

The decrease in adjusted net earnings for the first quarter of 2015 from the first quarter of 2014 was primarily due to:

- lower crude oil and NGLs netbacks in the North America and North Sea segments;
- lower realized SCO prices;
- lower natural gas netbacks in the North America segment; and
- higher depletion, depreciation and amortization expense;

partially offset by:

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

The decrease in adjusted net earnings for the first quarter of 2015 from the fourth quarter of 2014 was primarily due to:

- lower crude oil and NGLs netbacks in the North America and North Sea segments;
- lower realized SCO prices;
- lower natural gas netbacks in the North America segment;
- lower crude oil sales volumes in the North Sea and Offshore Africa segments; and
- lower realized risk management gains;

partially offset by:

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

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

Cash flow from operations for the first quarter of 2015 was $1,370 million compared with $2,146 million for the first quarter of 2014 and $2,368 million for the fourth quarter of 2014. The decreases in cash flow from operations from the comparable periods were primarily due to the factors noted above relating to the decreases in adjusted net earnings, partially offset by the impact of lower cash taxes.

Total production before royalties for the first quarter of 2015 increased 31% to 898,053 BOE/d from 684,647 BOE/d for the first quarter of 2014 and increased 4% from 860,920 BOE/d for the fourth 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)		**Mar 31 2015**		Dec 31 2014		Sep 30 2014		Jun 30 2014
Product sales	**$**	**3,226**	$	4,850	$	5,370	$	6,113
Net earnings (loss)	**$**	**(252)**	$	1,198	$	1,039	$	1,070
Net earnings (loss) per common share								
– basic	**$**	**(0.23)**	$	1.10	$	0.95	$	0.98
– diluted	**$**	**(0.23)**	$	1.09	$	0.94	$	0.97

($ millions, except per common share amounts)		Mar 31 2014		Dec 31 2013		Sept 30 2013		Jun 30 2013
Product sales	$	4,968	$	4,330	$	5,284	$	4,230
Net earnings (loss)	$	622	$	413	$	1,168	$	476
Net earnings (loss) per common share								
– basic	$	0.57	$	0.38	$	1.07	$	0.44
– diluted	$	0.57	$	0.38	$	1.07	$	0.44

Volatility in the quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – The impact of increased shale oil production in North America, fluctuating global supply/demand, 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 throughout 2013 and 2014, 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 across all segments, 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** – Fluctuations 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		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
WTI benchmark price (US$/bbl)	**$ 48.57**	$ 73.12	$ 98.61
Dated Brent benchmark price (US$/bbl)	**$ 53.80**	$ 75.99	$ 108.20
WCS blend differential from WTI (US$/bbl)	**$ 14.75**	$ 14.26	$ 23.27
WCS blend differential from WTI (%)	**30%**	20%	24%
SCO price (US$/bbl)	**$ 45.26**	$ 71.01	$ 96.45
Condensate benchmark price (US$/bbl)	**$ 45.59**	$ 70.54	$ 102.53
NYMEX benchmark price (US$/MMBtu)	**$ 2.96**	$ 3.95	$ 4.89
AECO benchmark price (C$/GJ)	**$ 2.80**	$ 3.80	$ 4.52
US/Canadian dollar average exchange rate (US$)	**$ 0.8057**	$ 0.8806	$ 0.9064

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Dated Brent ("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. In the first quarter of 2015, 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$48.57 per bbl for the first quarter of 2015, a decrease of 51% from US$98.61 per bbl for the first quarter of 2014, and a decrease of 34% from US$73.12 per bbl for the fourth quarter of 2014.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$53.80 per bbl for the first quarter of 2015, a decrease of 50% from US$108.20 per bbl for the first quarter of 2014, and a decrease of 29% from US$75.99 per bbl for the fourth quarter of 2014.

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. An oversupply of crude oil in the world market together with the Organization of the Petroleum Exporting Countries' ("OPEC") decision in November 2014 to not reduce crude oil production resulted in a decline in benchmark pricing. The growth of North American shale oil production continues to put downward pressure on crude oil benchmark pricing. In April 2015, WTI averaged US$54.63 per bbl and Brent averaged US$59.76 per bbl.

The WCS Heavy Differential averaged 30% for the first quarter of 2015 compared with 24% for the first quarter of 2014 and 20% for the fourth quarter of 2014. The WCS Heavy Differential widened for the first quarter of 2015 from the comparable periods in connection with the rapid decline in WTI benchmark pricing. In April 2015, the WCS Heavy Differential averaged US$14.37 per bbl or 26%.

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$45.26 per bbl for the first quarter of 2015, a decrease of 53% from US$96.45 per bbl for the first quarter of 2014, and decreased 36% from US$71.01 per bbl for the fourth quarter of 2014. The decrease in SCO pricing for the first quarter of 2015 from the comparable periods was primarily due to a decrease in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.96 per MMBtu for the first quarter of 2015, a decrease of 39% from US$4.89 per MMBtu for the first quarter of 2014, and a decrease of 25% from US$3.95 per MMBtu for the fourth quarter of 2014.

AECO natural gas prices for the first quarter of 2015 averaged $2.80 per GJ, a decrease of 38% from $4.52 per GJ for the first quarter of 2014, and a decrease of 26% from $3.80 per GJ for the fourth quarter of 2014.

US natural gas production continued to grow in the first quarter of 2015, resulting in natural gas inventories remaining at normal industry levels, leading to downward pressure on natural gas prices. Natural gas prices were higher in the comparable periods reflecting lower than average storage levels due to the cold winter temperatures in 2014.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**432,419**	409,976	348,187
North America – Oil Sands Mining and Upgrading (1)	**134,166**	128,090	113,095
North Sea	**23,036**	21,927	16,715
Offshore Africa	**13,188**	12,047	10,791
	602,809	572,040	488,788
Natural gas (MMcf/d)			
North America	**1,713**	1,705	1,147
North Sea	**34**	10	7
Offshore Africa	**24**	18	21
	1,771	1,733	1,175
Total barrels of oil equivalent (BOE/d)	**898,053**	860,920	684,647
Product mix			
Light and medium crude oil and NGLs	**15%**	15%	15%
Pelican Lake heavy crude oil	**6%**	6%	7%
Primary heavy crude oil	**15%**	17%	20%
Bitumen (thermal oil)	**16%**	14%	12%
Synthetic crude oil (1)	**15%**	15%	17%
Natural gas	**33%**	33%	29%
Percentage of product sales (1) (2) (excluding Midstream revenue)			
Crude oil and NGLs	**80%**	84%	86%
Natural gas	**20%**	16%	14%

(1) First quarter 2015 SCO production before royalties excludes 1,676 bbl/d of SCO consumed internally as diesel (fourth quarter 2014 – 1,288 bbl/d; first quarter 2014 – nil).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**380,273**	343,324	280,826
North America – Oil Sands Mining and Upgrading	**132,413**	121,292	106,891
North Sea	**22,976**	21,881	16,662
Offshore Africa	**12,586**	11,203	9,762
	548,248	497,700	414,141
Natural gas (MMcf/d)			
North America	**1,643**	1,606	1,017
North Sea	**34**	10	7
Offshore Africa	**23**	16	18
	1,700	1,632	1,042
Total barrels of oil equivalent (BOE/d)	**831,637**	769,775	587,737

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

Crude oil and NGLs production for the first quarter of 2015 increased 23% to 602,809 bbl/d from 488,788 bbl/d for the first quarter of 2014 and increased 5% from 572,040 bbl/d for the fourth quarter of 2014. The increase in production for the first quarter of 2015 from the comparable periods was primarily due to the increased production at the Company's thermal areas including Kirby South, strong and reliable production in Horizon, and higher production in North Sea and Offshore Africa. The increase from the first quarter of 2014 also reflected the increase in NGLs production associated with increased natural gas production. Crude oil and NGLs production for the first quarter of 2015 was within the Company's previously issued guidance of 591,000 to 617,000 bbl/d.

Natural gas production for the first quarter of 2015 increased 51% to 1,771 MMcf/d from 1,175 MMcf/d for the first quarter of 2014 and increased 2% from 1,733 MMcf/d for the fourth quarter of 2014. The increase in natural gas production for the first quarter of 2015 from the first quarter of 2014 was primarily a result of acquisitions of producing Canadian natural gas properties in 2014. The increase in natural gas production from the fourth quarter of 2014 was primarily due to acquisitions of producing Canadian natural gas properties in 2014 and higher production volumes in the North Sea and Offshore Africa segments. Natural gas production for the first quarter of 2015 was below the Company's previously issued guidance of 1,785 to 1,805 MMcf/d primarily due to lower natural gas production from an extended unplanned third party processing facility outage in British Columbia and lower than expected production in the North Sea. Late in the fourth quarter of 2014, the Company began exporting natural gas from the Banff field through the Banff FPSO. Natural gas exports have been impacted by FPSO operational reliability issues. Currently, the Company is working with the FPSO service provider to resolve these matters.

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. Second quarter 2015 production guidance is targeted to average between 513,000 and 540,000 bbl/d of crude oil and NGLs and between 1,750 and 1,770 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the first quarter of 2015 increased 24% to average 432,419 bbl/d compared with 348,187 bbl/d for the first quarter of 2014 and increased 5% from 409,976 bbl/d for the fourth quarter of 2014. The increase in production for the first quarter of 2015 from the first quarter of 2014 was primarily due to increased production in the Company's thermal areas including Kirby South and increased production related to the acquisitions of producing Canadian crude oil properties in 2014. The increase in production from the fourth quarter of 2014 was primarily related to the cyclic nature of the Company's thermal operations. First quarter 2015 production of crude oil and NGLs was within the Company's previously issued guidance of 427,000 to 442,000 bbl/d. Second quarter 2015 production guidance is targeted to average between 372,000 and 389,000 bbl/d of crude oil and NGLs.

Natural gas production increased 49% to 1,713 MMcf/d for the first quarter of 2015 compared with 1,147 MMcf/d in the first quarter of 2014 and was comparable with the fourth quarter of 2014. The increase in natural gas production for the first quarter of 2015 from the comparable periods was primarily a result of the acquisitions of producing Canadian natural gas properties in 2014 and growth from the current drilling program, partially offset by lower natural gas production from an extended unplanned third party processing facility outage in British Columbia.

North America – Oil Sands Mining and Upgrading

SCO production for the first quarter of 2015 increased 19% to 134,166 bbl/d from 113,095 bbl/d for the first quarter of 2014 and increased 5% from 128,090 bbl/d for the fourth quarter of 2014. Production increased for the first quarter of 2015 from the comparable periods as the Company continued to optimize operations, with the plant running at near nameplate capacity after the successful completion of the coker expansion in 2014. First quarter 2015 production of SCO was within the Company's previously issued guidance of 129,000 to 136,000 bbl/d. The turnaround originally planned for Fall 2015 has now been rescheduled to June 2015 to perform maintenance and other activities to enhance throughput and reliability. Second quarter 2015 production guidance is targeted to average between 107,000 to 113,000 bbl/d. Targeted average annual production guidance remains unchanged at 121,000 to 131,000 bbl/d.

North Sea

North Sea crude oil production for the first quarter 2015 increased 38% to 23,036 bbl/d from 16,715 bbl/d for the first quarter of 2014, and increased 5% from 21,927 bbl/d for the fourth quarter of 2014. The increase in production for the first quarter of 2015 from the comparable periods primarily reflected the reinstatement of production from both the Banff FPSO and the Tiffany platform in 2014. Late in the fourth quarter of 2014, the Company initiated natural gas exports from the Banff field through the Banff FPSO.

Offshore Africa

Offshore Africa crude oil production for the first quarter of 2015 averaged 13,188 bbl/d, increasing 22% from 10,791 bbl/d for the first quarter of 2014 and increasing 9% from 12,047 bbl/d for the fourth quarter of 2014. The increase in first quarter 2015 production reflected the Company's completion of a turnaround in the fourth quarter of 2014 and new well production on stream at the Espoir field in the first quarter of 2015, partially offset by natural field declines. The increase in production volumes from the first quarter of 2014 was due to the Baobab FPSO outage in early 2014 and new well production from the Espoir field in 2015.

International Guidance

The Company's North Sea and Offshore Africa first quarter 2015 crude oil production was 36,224 bbl/d and was within the Company's previously issued guidance of 35,000 to 39,000 bbl/d. Second quarter 2015 production guidance is targeted to average between 34,000 and 38,000 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)	**Mar 31 2015**	Dec 31 2014	Mar 31 2014
North America – Exploration and Production	**598,825**	930,116	1,069,537
North America – Oil Sands Mining and Upgrading (SCO)	**1,692,043**	1,266,063	1,693,887
North Sea	**562,540**	368,808	311,457
Offshore Africa	**1,086,222**	461,997	1,156,700
	3,939,630	3,026,984	4,231,581

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Crude oil and NGLs ($/bbl) [1]			
Sales price [2]	**$ 37.03**	$ 62.80	$ 79.68
Transportation	**2.46**	2.15	2.49
Realized sales price, net of transportation	**34.57**	60.65	77.19
Royalties	**3.83**	9.05	14.05
Production expense	**16.10**	18.69	19.18
Netback	**$ 14.64**	$ 32.91	$ 43.96
Natural gas ($/Mcf) [1]			
Sales price [2]	**$ 3.38**	$ 4.32	$ 5.69
Transportation	**0.36**	0.28	0.30
Realized sales price, net of transportation	**3.02**	4.04	5.39
Royalties	**0.12**	0.24	0.62
Production expense	**1.44**	1.39	1.61
Netback	**$ 1.46**	$ 2.41	$ 3.16
Barrels of oil equivalent ($/BOE) [1]			
Sales price [2]	**$ 30.57**	$ 48.23	$ 63.14
Transportation	**2.44**	2.05	2.29
Realized sales price, net of transportation	**28.13**	46.18	60.85
Royalties	**2.65**	6.10	10.42
Production expense	**13.20**	14.66	15.82
Netback	**$ 12.28**	$ 25.42	$ 34.61

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 35.22**	$ 61.28	$ 77.54
North Sea	**$ 64.59**	$ 83.32	$ 121.38
Offshore Africa	**$ 71.75**	$ 68.90	$ –
Company average	**$ 37.03**	$ 62.80	$ 79.68
Natural gas ($/Mcf) (1) (2)			
North America	**$ 3.14**	$ 4.22	$ 5.56
North Sea	**$ 10.18**	$ 8.22	$ 6.05
Offshore Africa	**$ 11.70**	$ 11.73	$ 12.18
Company average	**$ 3.38**	$ 4.32	$ 5.69
Company average ($/BOE) (1) (2)	**$ 30.57**	$ 48.23	$ 63.14

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

North America

North America realized crude oil prices averaged $35.22 per bbl for the first quarter of 2015, a decrease of 55% compared with $77.54 per bbl for the first quarter of 2014 and a decrease of 43% compared with $61.28 per bbl for the fourth quarter of 2014. The decrease in realized crude oil prices for the first quarter of 2015 from the comparable periods was primarily due to lower WTI benchmark pricing and a widening WCS Heavy Differential as a percentage of WTI, 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 first quarter of 2015 contributed approximately 179,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 44% to average $3.14 per Mcf for the first quarter of 2015 compared with $5.56 per Mcf in the first quarter of 2014, and decreased 26% compared with $4.22 per Mcf for the fourth quarter of 2014. US natural gas production continued to grow in the first quarter of 2015, resulting in natural gas inventories remaining at normal industry levels, leading to downward pressure on natural gas prices. Realized natural gas prices were higher in the comparable periods reflecting lower than average storage levels due to the cold winter temperatures in 2014.

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

(Quarterly Average)		**Mar 31 2015**		Dec 31 2014		Mar 31 2014
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs ($/bbl)	**$**	**38.78**	$	62.27	$	83.57
Pelican Lake heavy crude oil ($/bbl)	**$**	**36.21**	$	62.33	$	79.94
Primary heavy crude oil ($/bbl)	**$**	**37.64**	$	62.47	$	77.78
Bitumen (thermal oil) ($/bbl)	**$**	**30.25**	$	58.64	$	69.73
Natural gas ($/Mcf)	**$**	**3.14**	$	4.22	$	5.56

(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 47% to average $64.59 per bbl for the first quarter of 2015 from $121.38 per bbl for the first quarter of 2014 and decreased 22% from $83.32 per bbl for the fourth quarter of 2014. The decrease in realized crude oil prices for the first quarter of 2015 from the comparable periods reflected declines 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 increased 4% to average $71.75 per bbl for the first quarter of 2015 from $68.90 per bbl for the fourth quarter of 2014, reflecting prevailing Brent pricing at the time of liftings, together with the weakening of the Canadian dollar. Due to the timing of scheduled liftings from the various fields, the Company had no crude oil liftings during the first quarter of 2014. Accordingly, no crude oil revenue was recognized in the first quarter of 2014.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 4.02**	$ 9.76	$ 14.75
North Sea	**$ 0.16**	$ 0.17	$ 0.38
Offshore Africa	**$ 3.27**	$ 4.83	$ –
Company average	**$ 3.83**	$ 9.05	$ 14.05
Natural gas ($/Mcf) [1]			
North America	**$ 0.12**	$ 0.23	$ 0.60
Offshore Africa	**$ 0.54**	$ 0.99	$ 2.06
Company average	**$ 0.12**	$ 0.24	$ 0.62
Company average ($/BOE) [1]	**$ 2.65**	$ 6.10	$ 10.42

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

North America

North America crude oil and natural gas royalties for the first quarter of 2015 and the comparable periods reflected movements in benchmark commodity prices and fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 12% of product sales for the first quarter of 2015 compared with 20% for the first quarter of 2014 and 17% for the fourth quarter of 2014. The decrease in royalties for the first quarter of 2015 from the comparable periods was primarily due to lower 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 4% of product sales for the first quarter of 2015 compared with 11% for the first quarter of 2014 and 6% for the fourth quarter of 2014. The decrease in natural gas royalty rates for the first quarter of 2015 from the comparable periods was due to lower 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 approximately 5% for the first quarter of 2015 compared with 17% for the first quarter of 2014 and 7% for the fourth quarter of 2014. The decrease in royalties for the first quarter of 2015 from the fourth quarter of 2014 was primarily a result of the timing of liftings from various fields and the status of payout in the various fields. Royalties for the first quarter of 2014 related to natural gas sales only. 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		
	Mar 31 2015	Dec 31 2014	Mar 31 2014
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 13.75**	$ 14.38	$ 16.31
North Sea	**$ 65.23**	$ 68.64	$ 75.51
Offshore Africa	**$ 15.46**	$ 50.54	$ –
Company average	**$ 16.10**	$ 18.69	$ 19.18
Natural gas ($/Mcf) (1)			
North America	**$ 1.38**	$ 1.34	$ 1.54
North Sea	**$ 3.89**	$ 6.35	$ 5.83
Offshore Africa	**$ 2.80**	$ 3.35	$ 3.64
Company average	**$ 1.44**	$ 1.39	$ 1.61
Company average ($/BOE) (1)	**$ 13.20**	$ 14.66	$ 15.82

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

North America

North America crude oil and NGLs production expense for the first quarter of 2015 decreased 16% to $13.75 per bbl from $16.31 per bbl for the first quarter of 2014 and decreased 4% from $14.38 per bbl for the fourth quarter of 2014. The decrease in production expense for the first quarter of 2015 from the comparable periods reflected the Company's continuous focus on efficiencies and cost control across the asset base, production volume increases in thermal areas, and the integration of acquired properties. North America crude oil and NGLs production expense is anticipated to average $12.50 to $14.50 per bbl for 2015.

North America natural gas production expense for the first quarter of 2015 decreased 10% to $1.38 per Mcf from $1.54 per Mcf for the first quarter of 2014, and as expected, increased slightly compared with the fourth quarter of 2014 due to normal winter seasonal activities. Natural gas production expense for the first quarter of 2015 decreased from the first quarter of 2014 due to focused cost control across the asset base including integration of acquired properties. North America natural gas production expense is anticipated to average $1.25 to $1.35 per Mcf for 2015.

North Sea

North Sea crude oil production expense for the first quarter of 2015 decreased 14% to $65.23 per bbl from $75.51 per bbl for the first quarter of 2014 and decreased 5% from $68.64 per bbl for the fourth quarter of 2014. The decrease in production expense for the first quarter of 2015 from the comparable periods was primarily the result of higher production volumes on a relatively fixed cost structure, partially offset by the impact of the weaker Canadian dollar. North Sea crude oil production expense is anticipated to average $52.00 to $58.00 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 first quarter of 2015 averaged $15.46 per bbl, a decrease of 69% from $50.54 per bbl for the fourth quarter of 2014, primarily reflecting the impact of higher production volumes, lower product inventory valuation adjustments, and the timing of liftings from various fields, which have different cost structures. As there were no crude oil liftings during the first quarter of 2014, no crude oil production expense was recognized during the first quarter of 2014. Offshore Africa crude oil production expense is anticipated to average $24.00 to $28.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)	Three Months Ended **Mar 31 2015**		Dec 31 2014		Mar 31 2014
Expense	**$**	**1,213**	$ 1,210	$	879
$/BOE (1)	**$**	**17.78**	$ 17.76	$	17.55

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

Depletion, depreciation and amortization expense on a per barrel basis for the first quarter of 2015 was consistent with the comparable periods. The increase in depletion, depreciation and amortization expense from the first quarter of 2014 primarily reflected the increase in sales volumes in the first quarter of 2015.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)	Three Months Ended **Mar 31 2015**		Dec 31 2014		Mar 31 2014
Expense	**$**	**35**	$ 37	$	33
$/BOE (1)	**$**	**0.52**	$ 0.56	$	0.67

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

Asset retirement obligation accretion expense for the first quarter of 2015 decreased 22% to $0.52 per BOE from $0.67 per BOE for the first quarter of 2014 and decreased 7% from $0.56 per BOE for the fourth quarter of 2014, 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 first quarter of 2015, operating performance continued to be strong with the plant running at near nameplate capacity of 137,000 bbl/d, leading to average production of 134,166 bbl/d.

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

($/bbl)	Three Months Ended **Mar 31 2015**		Dec 31 2014		Mar 31 2014
SCO sales price (1)	**$**	**56.75**	$ 79.23	$	107.82
Bitumen value for royalty purposes (1) (2)	**$**	**29.70**	$ 56.98	$	66.27
Bitumen royalties (1) (3)	**$**	**1.01**	$ 4.44	$	5.06
Transportation	**$**	**1.83**	$ 1.76	$	1.96

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

Realized SCO sales prices averaged $56.75 per bbl for the first quarter of 2015, a decrease of 47% compared with $107.82 per bbl for the first quarter of 2014 and a decrease of 28% compared with $79.23 per bbl for the fourth quarter of 2014, reflecting lower benchmark pricing, partially offset by the impact of a weakening Canadian dollar.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

	Three Months Ended		
($ millions)	**Mar 31 2015**	Dec 31 2014	Mar 31 2014
Cash production costs, excluding natural gas costs	**$ 326**	$ 368	$ 375
Natural gas costs	**20**	27	37
Total cash production costs	**$ 346**	$ 395	$ 412

	Three Months Ended		
($/bbl) (1)	**Mar 31 2015**	Dec 31 2014	Mar 31 2014
Cash production costs, excluding natural gas costs	**$ 28.03**	$ 31.97	$ 37.39
Natural gas costs	**1.70**	2.37	3.72
Cash production costs	**$ 29.73**	$ 34.34	$ 41.11
Sales (bbl/d)	**129,433**	125,092	111,506

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

Cash production costs for the first quarter of 2015 averaged $29.73 per bbl, a decrease of 28% compared with $41.11 per bbl for the first quarter of 2014 and a decrease of 13% compared with $34.34 per bbl for the fourth quarter of 2014. The decrease in cash production costs for the first quarter of 2015 from comparable periods reflected the Company's continuous focus on cost control efficiencies and reliability. Cash production costs are anticipated to average $31.00 to $34.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2015**	Dec 31 2014	Mar 31 2014
Expense	**$ 139**	$ 194	$ 130
$/bbl (1)	**$ 11.96**	$ 16.85	$ 12.95

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

Depletion, depreciation and amortization expense on a per barrel basis for the first quarter of 2015 decreased 8% to $11.96 per bbl from $12.95 per bbl for the first quarter of 2014 and decreased 29% from $16.85 per bbl for the fourth quarter of 2014. Depletion, depreciation and amortization expense on a per barrel basis decreased for the first quarter of 2015 from the comparable periods primarily due to the impact of increased production on component depreciation determined on a straight-line basis in the first quarter of 2015, and minor asset derecognitions in the fourth quarter of 2014.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2015**	Dec 31 2014	Mar 31 2014
Expense	**$ 8**	$ 12	$ 12
$/bbl (1)	**$ 0.66**	$ 1.02	$ 1.17

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

Asset retirement obligation accretion expense for the first quarter of 2015 decreased 44% to $0.66 per bbl from $1.17 per bbl for the first quarter of 2014 and decreased 35% from $1.02 per bbl for the fourth quarter of 2014, primarily due to the impact of increased sales volumes.

MIDSTREAM

($ millions)	Three Months Ended Mar 31 2015	Dec 31 2014	Mar 31 2014
Revenue	**$ 35**	$ 29	$ 31
Production expense	**9**	7	9
Midstream cash flow	**26**	22	22
Depreciation	**3**	2	2
Equity loss from investment	**15**	5	1
Segment earnings before taxes	**$ 8**	$ 15	$ 19

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.

The Company, along with APMC, have each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During the first quarter of 2015, the Company and APMC each provided an additional $112 million of subordinated debt (year ended December 31, 2014 - $113 million). 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 first quarter of 2015, 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. As at March 31, 2015, Redwater Partnership had borrowings of $393 million under its secured $3,500 million syndicated credit facility.

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

($ millions, except per BOE amounts)	Three Months Ended Mar 31 2015	Dec 31 2014	Mar 31 2014
Expense	**$ 104**	$ 100	$ 90
$/BOE (1)	**$ 1.31**	$ 1.26	$ 1.49

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

Administration expense for the first quarter of 2015 decreased 12% to $1.31 per BOE from $1.49 per BOE for the first quarter of 2014 and increased 4% as expected from $1.26 per BOE for the fourth quarter of 2014. Administration expense per BOE decreased for the first quarter of 2015 from the first quarter of 2014 primarily due to the impact of higher sales volumes. Administration expense per BOE increased slightly from the fourth quarter of 2014 primarily due to lower overhead recoveries associated with the reduction in the capital expenditure program.

SHARE-BASED COMPENSATION

	Three Months Ended		
($ millions)	**Mar 31 2015**	Dec 31 2014	Mar 31 2014
Expense (Recovery)	**$ 64**	$ (144)	$ 143

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 $64 million share-based compensation expense for the three months ended March 31, 2015, 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 three months ended March 31, 2015, the Company capitalized $14 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (March 31, 2014 – $26 million costs).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended		
($ millions, except per BOE amounts and interest rates)	**Mar 31 2015**	Dec 31 2014	Mar 31 2014
Expense, gross	**$ 144**	$ 141	$ 115
Less: capitalized interest	**58**	57	47
Expense, net	**$ 86**	$ 84	$ 68
$/BOE (1)	**$ 1.07**	$ 1.05	$ 1.13
Average effective interest rate	**4.0%**	4.0%	4.3%

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

Gross interest and other financing expense for the first quarter of 2015 increased from the comparable periods primarily due to the impact of higher overall debt levels. Capitalized interest of $58 million for the three months ended March 31, 2015 was primarily related to the Horizon Phase 2/3 expansion.

The Company's average effective interest rate for the first quarter of 2015 decreased from the first quarter of 2014 primarily due to the issuance of debt securities during 2014 with lower interest rates**.**

Net interest and other financing expense for the first quarter of 2015 decreased 5% to $1.07 per BOE from $1.13 per BOE for the first quarter of 2014 and increased 2% from $1.05 per BOE for the fourth quarter of 2014. Net interest and other financing expense per BOE decreased for the first quarter of 2015 from the first quarter of 2014 primarily due to the impact of increased sales volumes, partially offset by the impact of higher overall debt levels.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended		
($ millions)	**Mar 31 2015**	Dec 31 2014	Mar 31 2014
Crude oil and NGLs financial instruments	**$ (117)**	$ (284)	$ –
Natural gas financial instruments	**–**	1	–
Foreign currency contracts	**(139)**	(52)	(75)
Realized gain	**(256)**	(335)	(75)
Crude oil and NGLs financial instruments	**12**	(403)	(3)
Natural gas financial instruments	**–**	(3)	45
Foreign currency contracts	**2**	2	7
Unrealized loss (gain)	**14**	(404)	49
Net gain	**$ (242)**	$ (739)	$ (26)

During the first quarter of 2015, net realized risk management gains were related to the settlement of crude oil and foreign currency contracts. The Company also recorded a net unrealized loss of $14 million ($9 million after-tax) on its risk management activities for the three months ended March 31, 2015 (December 31, 2014 – unrealized gain of $404 million; $303 million after-tax; March 31, 2014 – unrealized loss of $49 million; $38 million after-tax).

Complete details related to outstanding derivative financial instruments at March 31, 2015 are disclosed in note 12 to the Company’s unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended		
($ millions)	**Mar 31 2015**	Dec 31 2014	Mar 31 2014
Net realized (gain) loss	**$ (53)**	$ 18	$ (1)
Net unrealized loss [(1)]	**413**	106	118
Net loss	**$ 360**	$ 124	$ 117

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

The net realized foreign exchange gain for the three months ended March 31, 2015 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange loss for the three months ended March 31, 2015 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt. The net unrealized loss for each of the periods presented included the impact of cross currency swaps (three months ended March 31, 2015 – unrealized gain of $314 million, December 31, 2014 – unrealized gain of $115 million, March 31, 2014 – unrealized gain of $100 million). The US/Canadian dollar exchange rate at March 31, 2015 was US$0.7885 (December 31, 2014 – US$0.8620; March 31, 2014 – US$0.9047).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Mar 31 2015	Dec 31 2014	Mar 31 2014
North America [1]	**$ 8**	$ 123	$ 192
North Sea	**(64)**	(23)	(15)
Offshore Africa	**2**	8	4
PRT recovery – North Sea	**(54)**	(86)	(61)
Other taxes	**3**	5	6
Current income tax (recovery) expense	**(105)**	27	126
Deferred income tax (recovery) expense	**(289)**	254	91
Deferred PRT expense (recovery) – North Sea	**7**	(1)	66
Deferred income tax (recovery) expense	**(282)**	253	157
	(387)	280	283
Income tax rate and other legislative changes [2]	**228**	–	–
	$ (159)	$ 280	$ 283
Effective income tax rate on adjusted net earnings from operations [3]	**105.8%**	25.7%	23.5%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.

(2) During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and the Petroleum Revenue Tax ("PRT"), and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in deferred income tax liabilities of approximately $228 million.

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

The current PRT recovery in the North Sea in the first quarter of 2015 and the comparative quarters reflects the impact of abandonment expenditures on the Murchison platform.

The effective income tax rate in the first quarter of 2015 included the impact of non-taxable items in North America and the North Sea as well as the impact of differences in jurisdictional tax rates in the countries in which the Company operates, in relation to net earnings. In March 2015, the UK government enacted legislation that reduced the supplementary charge on oil and gas profits from 32% to 20% effective January 1, 2015. In addition, the legislation reduced the PRT rate from 50% to 35% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes are still recoverable at the previous tax rate of 50%. The legislation also replaced the existing Brownfield Allowance with a new Investment Allowance on qualifying capital expenditures, effective April 1, 2015. The new Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions. As a result of the income tax changes, the deferred income tax liability was reduced by $217 million and the deferred PRT liability was reduced by $11 million.

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

For 2015, based on forward commodity prices and the current availability of tax pools, the Company expects to incur current income tax expense of $275 million to $375 million in Canada and recoveries of $240 million to $290 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Mar 31 2015	Dec 31 2014	Mar 31 2014
Exploration and Evaluation			
Net expenditures [2]	**$ 46**	$ 97	$ 117
Property, Plant and Equipment			
Net property acquisitions [2]	**11**	72	(4)
Well drilling, completion and equipping	**292**	582	641
Production and related facilities	**314**	482	415
Capitalized interest and other [3]	**26**	28	23
Net expenditures	**643**	1,164	1,075
Total Exploration and Production	**689**	1,261	1,192
Oil Sands Mining and Upgrading			
Horizon Phase 2/3 construction costs	**406**	739	444
Sustaining capital	**88**	83	60
Turnaround costs	**4**	8	2
Capitalized interest and other [3]	**71**	32	73
Total Oil Sands Mining and Upgrading	**569**	862	579
Midstream	**3**	(16)	25
Abandonments [4]	**144**	101	87
Head office	**7**	12	10
Total net capital expenditures	**$ 1,412**	$ 2,220	$ 1,893
By segment			
North America [2]	**$ 501**	$ 1,029	$ 1,087
North Sea	**62**	105	88
Offshore Africa	**126**	127	17
Oil Sands Mining and Upgrading	**569**	862	579
Midstream	**3**	(16)	25
Abandonments [4]	**144**	101	87
Head office	**7**	12	10
Total	**$ 1,412**	$ 2,220	$ 1,893

(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) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(4) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

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

In January 2015, the Company announced that it would reduce capital spending by approximately $2,400 million. In March 2015, capital expenditure guidance for 2015 was reduced by an additional $150 million and in May 2015, was further reduced by approximately $300 million. The Company has additional capital flexibility in 2015 to further curtail capital spending if required or to increase capital spending if commodity prices strengthen.

Net capital expenditures for the first quarter of 2015 were $1,412 million compared with $1,893 million for the first quarter of 2014 and $2,220 million for the fourth quarter of 2014. The decrease in capital expenditures for the first quarter of 2015 from the comparable periods primarily reflected the Company's previously announced capital allocation strategy.

Drilling Activity

	Three Months Ended		
(number of wells)	**Mar 31 2015**	Dec 31 2014	Mar 31 2014
Net successful natural gas wells	**9**	16	25
Net successful crude oil wells [(1)]	**42**	325	271
Dry wells	**2**	8	3
Stratigraphic test / service wells	**86**	74	330
Total	**139**	423	629
Success rate (excluding stratigraphic test / service wells)	**96%**	98%	99%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 40% of the total capital expenditures for the three months ended March 31, 2015 compared with approximately 62% for the three months ended March 31, 2014.

During the first quarter of 2015, the Company targeted 9 net natural gas wells, including 2 wells in Northeast British Columbia, 6 wells in Northwest Alberta and 1 well in Northern Plains. The Company also targeted 43 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 36 primary heavy crude oil wells, 1 light crude oil well, and 3 thermal oil wells were drilled. Another 3 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the first quarter of 2015 averaged approximately 146,100 bbl/d compared with approximately 82,100 bbl/d for the first quarter of 2014 and approximately 119,000 bbl/d for the fourth 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.

At Primrose, the final causation review report was submitted to the Alberta Energy Regulator. The submission represented the final stage of the review into the cause of the seepage to surface events. The Company has enhanced its understanding of operational practices and has applied these learnings in its approach to mitigate the risk of future seepages. 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 51,100 bbl/d for the first quarter of 2015 compared with 48,000 bbl/d for the first quarter of 2014 and 50,700 bbl/d for the fourth 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 commenced 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 first quarter of 2015 was focused on field construction of the hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit, tank farms, 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, tailings retrofit, sourwater concentrator, combined hydrotreater and sulphur recovery unit.

Targeted capital spending in 2015 has been further revised from $2,200 million to $2,150 million through targeted cost efficiencies, while maintaining planned expansion activities.

North Sea

The Company reduced its 2015 drilling program to one injection 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

In Côte d'Ivoire, late in the first quarter of 2015, the Company commenced production from the first well of the Espoir infill drilling program. This well is currently producing at a net rate of approximately 3,000 bbl/d. In April 2015, the Company commenced production from its second well at a net production rate of approximately 2,100 bbl/d. Production from both wells is above expectations. The Espoir drilling program is currently tracking to below its original sanction costs for the ten gross well program.

At the Baobab field, as part of a six well drilling program, the Company commenced drilling with production targeted to be on stream in June 2015.

In Block CI-514, the Company has a 36% non-operated interest. In the second quarter of 2014, the operator completed drilling the first exploratory well and encountered the presence of light oil. As a follow-up, in April 2015, a second exploratory well was drilled to evaluate the potential of the initial well. The second exploratory well has been plugged and abandoned, and the results will be evaluated and integrated into the Company's understanding of the block.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Mar 31 2015**	Dec 31 2014	Mar 31 2014
Working capital deficit (1)	**$ 13**	$ 673	$ 1,025
Long-term debt (2) (3)	**$ 15,689**	$ 14,002	$ 10,354
Share capital	**$ 4,474**	$ 4,432	$ 4,100
Retained earnings	**23,905**	24,408	22,193
Accumulated other comprehensive income	**36**	51	44
Shareholders' equity	**$ 28,415**	$ 28,891	$ 26,337
Debt to book capitalization (3) (4)	**36%**	33%	28%
Debt to market capitalization (3) (5)	**27%**	26%	18%
After-tax return on average common shareholders' equity (6)	**11%**	14%	11%
After-tax return on average capital employed (3) (7)	**8%**	10%	8%

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

At March 31, 2015, 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, 2014. 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 and the first quarter of 2015, the Company continues to exercise 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.

As at March 31, 2015, the Company had in place bank credit facilities of $7,128 million, of which $3,269 million, net of commercial paper issuances of $634 million, was available for general corporate purposes. The Company reserves capacity under its bank credit facilities for amounts outstanding under the US commercial paper program. Borrowings of up to a maximum US$1,500 million are authorized.

At March 31, 2015, the Company had $1,033 million of long-term debt maturing over the next 12 months ($400 million due June 2015, US$500 million due March 2016).

Long-term debt was $15,689 million at March 31, 2015, resulting in a debt to book capitalization ratio of 36% (December 31, 2014 – 33%; March 31, 2014 – 28%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. The Company has hedged a portion of its production for 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 March 31, 2015 are discussed in note 5 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at May 6, 2015, 50,000 bbl/d of currently forecasted crude oil volumes were hedged using price collars for the remainder of 2015. Further details related to the Company's commodity derivative financial instruments outstanding at March 31, 2015 are discussed in note 12 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at March 31, 2015, there were 1,092,941,000 common shares outstanding (December 31, 2014 –1,091,837,000 common shares) and 70,217,000 stock options outstanding. As at May 5, 2015, the Company had 1,094,221,000 common shares outstanding and 68,639,000 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 2015, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), during the twelve month period commencing April 2015 and ending April 2016, up to 54,640,607 common shares. The Company's Normal Course Issuer Bid announced in 2014 expired April 2015.

For the three months ended March 31, 2015, the Company did not purchase any common shares for cancellation.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at March 31, 2015:

($ millions)	Remaining 2015	2016	2017	2018	2019	Thereafter
Product transportation and pipeline	$ 367	$ 354	$ 324	$ 284	$ 248	$ 1,527
Offshore equipment operating leases and offshore drilling	$ 290	$ 101	$ 72	$ 65	$ 21	$ –
Long-term debt (1)	$ 1,034	$ 1,064	$ 3,008	$ 2,767	$ 1,000	$ 6,898
Interest and other financing expense (2)	$ 434	$ 600	$ 507	$ 415	$ 378	$ 4,586
Office leases	$ 32	$ 42	$ 45	$ 46	$ 48	$ 292
Other	$ 151	$ 126	$ 41	$ 1	$ 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 March 31, 2015.

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 audited 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, 2014.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Mar 31 2015	Dec 31 2014
ASSETS			
Current assets			
Cash and cash equivalents		**$ 34**	$ 25
Accounts receivable		**1,458**	1,889
Current income taxes		**562**	228
Inventory		**716**	665
Prepaids and other		**178**	172
Current portion of other long-term assets	4	**600**	510
		3,548	3,489
Exploration and evaluation assets	2	**3,531**	3,557
Property, plant and equipment	3	**52,698**	52,480
Other long-term assets	4	**922**	674
		$ 60,699	$ 60,200
LIABILITIES			
Current liabilities			
Accounts payable		**$ 598**	$ 564
Accrued liabilities		**2,651**	3,279
Current portion of long-term debt	5	**1,667**	980
Current portion of other long-term liabilities	6	**312**	319
		5,228	5,142
Long-term debt	5	**14,022**	13,022
Other long-term liabilities	6	**4,269**	4,175
Deferred income taxes		**8,765**	8,970
		32,284	31,309
SHAREHOLDERS' EQUITY			
Share capital	8	**4,474**	4,432
Retained earnings		**23,905**	24,408
Accumulated other comprehensive income	9	**36**	51
		28,415	28,891
		$ 60,699	$ 60,200

Commitments and contingencies (note 13).

Approved by the Board of Directors on May 6, 2015

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Mar 31 2015**	 Mar 31 2014
Product sales		**$ 3,226**	$ 4,968
Less: royalties		**(192)**	(572)
Revenue		**3,034**	4,396
Expenses			
Production		**1,253**	1,211
Transportation and blending		**635**	831
Depletion, depreciation and amortization	3	**1,355**	1,011
Administration		**104**	90
Share-based compensation	6	**64**	143
Asset retirement obligation accretion	6	**43**	45
Interest and other financing expense		**86**	68
Risk management activities	12	**(242)**	(26)
Foreign exchange loss		**360**	117
Equity loss from investment	4	**15**	1
		3,673	3,491
Earnings (loss) before taxes		**(639)**	905
Current income tax (recovery) expense	7	**(105)**	126
Deferred income tax (recovery) expense	7	**(282)**	157
Net earnings (loss)		**$ (252)**	$ 622
Net earnings (loss) per common share			
Basic	11	**$ (0.23)**	$ 0.57
Diluted	11	**$ (0.23)**	$ 0.57

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended **Mar 31 2015**	 Mar 31 2014
Net earnings (loss)	**$ (252)**	$ 622
Items that may be reclassified subsequently to net earnings (loss)		
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized income (loss), net of taxes of $1 million (2014 – $nil)	**(9)**	1
Reclassification to net earnings (loss), net of taxes of $nil (2014 – $nil)	**(2)**	3
	(11)	4
Foreign currency translation adjustment		
Translation of net investment	**(4)**	(2)
Other comprehensive income (loss), net of taxes	**(15)**	2
Comprehensive income (loss)	**$ (267)**	$ 624

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Mar 31 2015	Mar 31 2014
Share capital	8		
Balance – beginning of period		**$ 4,432**	$ 3,854
Issued upon exercise of stock options		**35**	195
Previously recognized liability on stock options exercised for common shares		**7**	57
Purchase of common shares under Normal Course Issuer Bid		**–**	(6)
Balance – end of period		**4,474**	4,100
Retained earnings			
Balance – beginning of period		**24,408**	21,876
Net earnings (loss)		**(252)**	622
Purchase of common shares under Normal Course Issuer Bid	8	**–**	(59)
Dividends on common shares	8	**(251)**	(246)
Balance – end of period		**23,905**	22,193
Accumulated other comprehensive income	9		
Balance – beginning of period		**51**	42
Other comprehensive income (loss), net of taxes		**(15)**	2
Balance – end of period		**36**	44
Shareholders' equity		**$ 28,415**	$ 26,337

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2015	Mar 31 2014
Operating activities		
Net earnings (loss)	**$ (252)**	$ 622
Non-cash items		
Depletion, depreciation and amortization	**1,355**	1,011
Share-based compensation	**64**	143
Asset retirement obligation accretion	**43**	45
Unrealized risk management loss	**14**	49
Unrealized foreign exchange loss	**413**	118
Equity loss from investment	**15**	1
Deferred income tax (recovery) expense	**(282)**	157
Other	**42**	31
Abandonment expenditures	**(144)**	(87)
Net change in non-cash working capital	**(14)**	(737)
	1,254	1,353
Financing activities		
Issue (repayment) of bank credit facilities and commercial paper, net	**877**	(661)
Issue of US dollar debt securities, net	**–**	1,100
Issue of common shares on exercise of stock options	**35**	195
Purchase of common shares under Normal Course Issuer Bid	**–**	(65)
Dividends on common shares	**(245)**	(217)
Net change in non-cash working capital	**(13)**	(5)
	654	347
Investing activities		
Net expenditures on exploration and evaluation assets	**(46)**	(117)
Net expenditures on property, plant and equipment	**(1,222)**	(1,689)
Investment in other long-term assets	**(112)**	–
Net change in non-cash working capital	**(519)**	109
	(1,899)	(1,697)
Increase in cash and cash equivalents	**9**	3
Cash and cash equivalents – beginning of period	**25**	16
Cash and cash equivalents – end of period	**$ 34**	$ 19
Interest paid	**$ 156**	$ 135
Income taxes paid	**$ 209**	$ 455

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, 2014. 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, 2014.

2. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	**North Sea**	**Offshore Africa**		
Cost					
At December 31, 2014	$ 3,426	$ –	$ 131	$ –	$ 3,557
Additions	**44**	**–**	**2**	**–**	**46**
Transfers to property, plant and equipment	**(78)**	**–**	**–**	**–**	**(78)**
Foreign exchange adjustments	–	**–**	**6**	**–**	**6**
At March 31, 2015	**$ 3,392**	**$ –**	**$ 139**	**$ –**	**$ 3,531**

3. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2014	$ 60,606	$ 6,182	$ 3,858	$ 21,948	$ 570	$ 352	$ 93,516
Additions	**462**	**62**	**124**	**569**	**3**	**7**	**1,227**
Transfers from E&E assets	**78**	–	–	–	–	–	**78**
Disposals/derecognitions	**(88)**	–	–	**(4)**	–	–	**(92)**
Foreign exchange adjustments and other	–	**581**	**364**	–	–	–	**945**
At March 31, 2015	**$ 61,058**	**$ 6,825**	**$ 4,346**	**$ 22,513**	**$ 573**	**$ 359**	**$ 95,674**
Accumulated depletion and depreciation							
At December 31, 2014	$ 31,886	$ 4,049	$ 2,890	$ 1,864	$ 120	$ 227	$ 41,036
Expense	**1,098**	**86**	**22**	**139**	**3**	**7**	**1,355**
Disposals/derecognitions	**(88)**	**–**	–	**(4)**	**–**	**–**	**(92)**
Foreign exchange adjustments and other	**(2)**	**394**	**283**	**2**	**–**	**–**	**677**
At March 31, 2015	**$ 32,894**	**$ 4,529**	**$ 3,195**	**$ 2,001**	**$ 123**	**$ 234**	**$ 42,976**
Net book value							
– at March 31, 2015	**$ 28,164**	**$ 2,296**	**$ 1,151**	**$ 20,512**	**$ 450**	**$ 125**	**$ 52,698**
– at December 31, 2014	$ 28,720	$ 2,133	$ 968	$ 20,084	$ 450	$ 125	$ 52,480

Project costs not subject to depletion and depreciation	**Mar 31 2015**	Dec 31 2014
Horizon	**$ 5,909**	$ 5,492
Kirby Thermal Oil Sands – North	**$ 748**	$ 681

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. For the three months ended March 31, 2015, pre-tax interest of $58 million (March 31, 2014 – $47 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 4.0% (March 31, 2014 – 4.3%).

4. OTHER LONG-TERM ASSETS

		Mar 31 2015		Dec 31 2014
Investment in North West Redwater Partnership	**$**	**283**	$	298
North West Redwater Partnership subordinated debt [(1)]		**238**		120
Risk Management (note 12)		**881**		599
Other		**120**		167
		1,522		1,184
Less: current portion		**600**		510
	$	**922**	$	674

(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.

The Company, along with APMC, have each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During the first quarter of 2015, the Company and APMC each provided an additional $112 million of subordinated debt (year ended December 31, 2014 - $113 million). 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 first quarter of 2015, 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. As at March 31, 2015, Redwater Partnership had borrowings of $393 million under its secured $3,500 million syndicated credit facility.

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.

5. LONG-TERM DEBT

		Mar 31 2015		Dec 31 2014
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**2,648**	$	2,404
Medium-term notes		**2,400**		2,400
		5,048		4,804
US dollar denominated debt, unsecured				
Bank credit facilities (March 31, 2015 – US$455 million; December 31, 2014 – $nil)	**$**	**577**	$	–
Commercial paper (US$500 million)		**634**		580
US dollar debt securities (US$7,500 million)		**9,512**		8,701
Less: original issue discount on US dollar debt securities (1)		**(20)**		(21)
		10,703		9,260
Long-term debt before transaction costs		**15,751**		14,064
Less: transaction costs (1) (2)		**(62)**		(62)
		15,689		14,002
Less: current portion of commercial paper		**634**		580
current portion of long-term debt (1) (2)		**1,033**		400
	$	**14,022**	$	13,022

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

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

Bank Credit Facilities and Commercial Paper

As at March 31, 2015, the Company had in place bank credit facilities of $7,128 million available for general corporate purposes, comprised of:

- a $100 million demand credit facility;
- a $1,500 million revolving syndicated credit facility maturing June 2016;
- a $1,000 million non-revolving term credit facility maturing January 2017;
- a $3,000 million revolving syndicated credit facility maturing June 2017;
- a $1,500 million non-revolving term credit facility maturing April 2018; 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 revolving 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.

During the first quarter of 2015, the Company extended the $1,000 million non-revolving term credit facility, originally maturing March 2016, to January 2017. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers’ acceptances or Canadian prime loans. In addition, the Company entered into a new $1,500 million non-revolving three-year term credit facility maturing April 2018. Borrowings under the $1,500 million non-revolving term 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.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at March 31, 2015 was 1.8% (March 31, 2014 – 1.6%), and on long-term debt outstanding for the three months ended March 31, 2015 was 4.0% (March 31, 2014 – 4.3%).

At March 31, 2015 letters of credit and guarantees aggregating $377 million, including a $39 million financial guarantee related to Horizon and $223 million of letters of credit related to North Sea operations, were outstanding. The letters of credit are supported by dedicated credit facilities.

Medium-Term Notes

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.

US Dollar Debt 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.

6. OTHER LONG-TERM LIABILITIES

	Mar 31 2015	Dec 31 2014
Asset retirement obligations	**$ 4,254**	$ 4,221
Share-based compensation	**273**	203
Other	**54**	70
	4,581	4,494
Less: current portion	**312**	319
	$ 4,269	$ 4,175

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, 2014 – 4.6%). A reconciliation of the discounted asset retirement obligations was as follows:

	Mar 31 2015	Dec 31 2014
Balance – beginning of period	**$ 4,221**	$ 4,162
Liabilities incurred	**3**	41
Liabilities acquired	**2**	404
Liabilities settled	**(144)**	(346)
Asset retirement obligation accretion	**43**	193
Revision of cost, inflation rates and timing estimates	**–**	(907)
Change in discount rate	**–**	558
Foreign exchange adjustments	**129**	116
Balance – end of period	**4,254**	4,221
Less: current portion	**78**	121
	$ 4,176	$ 4,100

Share-Based Compensation

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

	Mar 31 2015	Dec 31 2014
Balance – beginning of period	**$ 203**	$ 260
Share-based compensation expense	**64**	66
Cash payment for stock options surrendered	**(1)**	(8)
Transferred to common shares	**(7)**	(129)
Capitalized to Oil Sands Mining and Upgrading	**14**	14
Balance – end of period	**273**	203
Less: current portion	**207**	158
	$ 66	$ 45

7. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended	
	Mar 31 2015	Mar 31 2014
Current corporate income tax expense – North America	**$ 8**	$ 192
Current corporate income tax recovery – North Sea	**(64)**	(15)
Current corporate income tax expense – Offshore Africa	**2**	4
Current PRT (1) recovery – North Sea	**(54)**	(61)
Other taxes	**3**	6
Current income tax (recovery) expense	**(105)**	126
Deferred corporate income tax (recovery) expense	**(289)**	91
Deferred PRT (1) expense – North Sea	**7**	66
Deferred income tax (recovery) expense	**(282)**	157
Income tax (recovery) expense	**$ (387)**	$ 283

(1) Petroleum Revenue Tax.

In March 2015, the UK government enacted legislation that reduced the supplementary charge on oil and gas profits from 32% to 20% effective January 1, 2015. In addition, the legislation reduced the PRT rate from 50% to 35% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes are still recoverable at the previous tax rate of 50%. The legislation also replaced the existing Brownfield Allowance with a new Investment Allowance on qualifying capital expenditures, effective April 1, 2015. The new Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions. As a result of the income tax changes, the deferred income tax liability was reduced by $217 million and the deferred PRT liability was reduced by $11 million.

8. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued common shares	Three Months Ended Mar 31, 2015 Number of shares (thousands)		Amount
Balance – beginning of period	**1,091,837**	$	**4,432**
Issued upon exercise of stock options	**1,104**		**35**
Previously recognized liability on stock options exercised for common shares	**–**		**7**
Balance – end of period	**1,092,941**	$	**4,474**

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 2015, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, during the twelve month period commencing April 2015 and ending April 2016, up to 54,640,607 common shares. The Company's Normal Course Issuer Bid announced in 2014 expired April 2015.

For the three months ended March 31, 2015, the Company did not purchase any common shares for cancellation.

Stock Options

The following table summarizes information relating to stock options outstanding at March 31, 2015:

	Three Months Ended Mar 31, 2015 Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of period	**71,708**	$	**35.60**
Granted	**4,697**	$	**33.16**
Surrendered for cash settlement	**(92)**	$	**32.98**
Exercised for common shares	**(1,104)**	$	**31.96**
Forfeited	**(4,992)**	$	**34.65**
Outstanding – end of period	**70,217**	$	**35.56**
Exercisable – end of period	**19,852**	$	**36.82**

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.

9. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Mar 31 2015	Mar 31 2014
Derivative financial instruments designated as cash flow hedges	**$ 83**	$ 85
Foreign currency translation adjustment	**(47)**	(41)
	$ 36	$ 44

10. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At March 31, 2015, the ratio was within the target range at 36%.

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

	Mar 31 2015	Dec 31 2014
Long-term debt [(1)]	**$ 15,689**	$ 14,002
Total shareholders' equity	**$ 28,415**	$ 28,891
Debt to book capitalization	**36%**	33%

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

11. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended	
	Mar 31 2015	Mar 31 2014
Weighted average common shares outstanding – basic (thousands of shares)	**1,092,350**	1,089,929
Effect of dilutive stock options (thousands of shares) [(1)]	**–**	3,298
Weighted average common shares outstanding – diluted (thousands of shares)	**1,092,350**	1,093,227
Net earnings (loss)	**$ (252)**	$ 622
Net earnings (loss) per common share – basic	**$ (0.23)**	$ 0.57
– diluted	**$ (0.23)**	$ 0.57

(1) For the three months ended March 31, 2015, the dilutive effect of 2,053,000 options has not been included in the determination of the weighted average number of common shares outstanding as the inclusion would be anti-dilutive to the net loss per common share.

12. FINANCIAL INSTRUMENTS

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

	Mar 31, 2015				
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	**$ 1,458**	**$ –**	**$ –**	**$ –**	**$ 1,458**
Other long-term assets	**238**	**399**	**482**	**–**	**1,119**
Accounts payable	**–**	**–**	**–**	**(598)**	**(598)**
Accrued liabilities	**–**	**–**	**–**	**(2,651)**	**(2,651)**
Other long-term liabilities	**–**	**–**	**–**	**(27)**	**(27)**
Long-term debt (1)	**–**	**–**	**–**	**(15,689)**	**(15,689)**
	$ 1,696	**$ 399**	**$ 482**	**$ (18,965)**	**$ (16,388)**

	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)

(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:

	Mar 31, 2015			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3**
Other long-term assets (3)	**$ 1,119**	**$ –**	**$ 881**	**$ 238**
Fixed rate long-term debt (4) (5)	**$ (11,830)**	**$ (12,904)**	**$ –**	**$ –**

	Dec 31, 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)	$ –	$ –

(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.

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

Asset (liability)		Mar 31, 2015		Dec 31, 2014
Derivatives held for trading				
Crude oil price collars	**$**	**382**	$	410
Crude oil WCS [(1)] differential swaps		**–**		(16)
Foreign currency forward contracts		**17**		21
Cash flow hedges				
Foreign currency forward contracts		**7**		11
Cross currency swaps		**475**		173
	$	**881**	$	599
Included within:				
Current portion of other long-term assets	**$**	**521**	$	436
Other long-term assets		**360**		163
	$	**881**	$	599

(1) Western Canadian Select.

For the three months ended March 31, 2015, the Company recognized a gain of $2 million (year ended December 31, 2014 – loss of $3 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)		Three Months Ended Mar 31, 2015		Year Ended Dec 31, 2014
Balance – beginning of period	**$**	**599**	$	(136)
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**(14)**		451
Foreign exchange		**308**		270
Other comprehensive income (loss)		**(12)**		14
Balance – end of period		**881**		599
Less: current portion		**521**		436
	$	**360**	$	163

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

	Three Months Ended	
	Mar 31 2015	Mar 31 2014
Net realized risk management gain	**$ (256)**	$ (75)
Net unrealized risk management loss	**14**	49
	$ (242)	$ (26)

Financial Risk Factors

a) Market risk

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

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At March 31, 2015, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Price collars	Apr 2015 – Dec 2015	50,000 bbl/d	US$80.00 – US$120.52	Brent

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At March 31, 2015 the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At March 31, 2015, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Apr 2015	–	Mar 2016	US$500	1.109	Three-month LIBOR plus 0.375%	Three-month CDOR (1) plus 0.309%
	Apr 2015	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Apr 2015	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Apr 2015	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Apr 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 March 31, 2015 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at March 31, 2015, the Company had US$2,222 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$955 million designated as cash flow hedges.

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At March 31, 2015, 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. At March 31, 2015, the Company had net risk management assets of $894 million with specific counterparties related to derivative financial instruments (December 31, 2014 – $622 million).

c) Liquidity risk

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

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

The maturity dates for financial liabilities were as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	598	$	–	$	–	$	–
Accrued liabilities	$	2,651	$	–	$	–	$	–
Other long-term liabilities	$	27	$	–	$	–	$	–
Long-term debt (1)	$	1,668	$	1,429	$	5,776	$	6,898

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

13. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

		Remaining 2015		2016		2017		2018		2019		Thereafter
Product transportation and pipeline	$	367	$	354	$	324	$	284	$	248	$	1,527
Offshore equipment operating leases and offshore drilling	$	290	$	101	$	72	$	65	$	21	$	–
Office leases	$	32	$	42	$	45	$	46	$	48	$	292
Other	$	151	$	126	$	41	$	1	$	1	$	–

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

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

14. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	Exploration and Production							
	North America		North Sea		Offshore Africa		Total Exploration and Production	
	Three Months Ended Mar 31		Three Months Ended Mar 31		Three Months Ended Mar 31		Three Months Ended Mar 31	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014
Segmented product sales	**2,334**	3,657	**152**	198	**67**	24	**2,553**	3,879
Less: royalties	**(177)**	(516)	**–**	(1)	**(3)**	(4)	**(180)**	(521)
Segmented revenue	**2,157**	3,141	**152**	197	**64**	20	**2,373**	3,358
Segmented expenses								
Production	**751**	663	**134**	123	**15**	7	**900**	793
Transportation and blending	**620**	828	**13**	2	**1**	–	**634**	830
Depletion, depreciation and amortization	**1,104**	816	**87**	58	**22**	5	**1,213**	879
Asset retirement obligation accretion	**23**	22	**9**	9	**3**	2	**35**	33
Realized risk management activities	**(256)**	(75)	**–**	–	**–**	–	**(256)**	(75)
Equity loss from investment	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**2,242**	2,254	**243**	192	**41**	14	**2,526**	2,460
Segmented earnings (loss) before the following	**(85)**	887	**(91)**	5	**23**	6	**(153)**	898
Non-segmented expenses								
Administration								
Share-based compensation								
Interest and other financing expense								
Unrealized risk management activities								
Foreign exchange loss								
Total non-segmented expenses								
Earnings (loss) before taxes								
Current income tax (recovery) expense								
Deferred income tax (recovery) expense								
Net earnings (loss)								

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading		Midstream		Inter-segment elimination and other		Total	
	Three Months Ended Mar 31		Three Months Ended Mar 31		Three Months Ended Mar 31		Three Months Ended Mar 31	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014
Segmented product sales	**660**	1,082	**35**	31	**(22)**	(24)	**3,226**	4,968
Less: royalties	**(12)**	(51)	**–**	–	**–**	–	**(192)**	(572)
Segmented revenue	**648**	1,031	**35**	31	**(22)**	(24)	**3,034**	4,396
Segmented expenses								
Production	**346**	412	**9**	9	**(2)**	(3)	**1,253**	1,211
Transportation and blending	**21**	20	**–**	–	**(20)**	(19)	**635**	831
Depletion, depreciation and amortization	**139**	130	**3**	2	**–**	–	**1,355**	1,011
Asset retirement obligation accretion	**8**	12	**–**	–	**–**	–	**43**	45
Realized risk management activities	**–**	–	**–**	–	**–**	–	**(256)**	(75)
Equity loss from investment	**–**	–	**15**	1	**–**	–	**15**	1
Total segmented expenses	**514**	574	**27**	12	**(22)**	(22)	**3,045**	3,024
Segmented earnings (loss) before the following	**134**	457	**8**	19	-	(2)	**(11)**	1,372
Non-segmented expenses								
Administration							**104**	90
Share-based compensation							**64**	143
Interest and other financing expense							**86**	68
Unrealized risk management activities							**14**	49
Foreign exchange loss							**360**	117
Total non-segmented expenses							**628**	467
Earnings (loss) before taxes							**(639)**	905
Current income tax (recovery) expense							**(105)**	126
Deferred income tax (recovery) expense							**(282)**	157
Net earnings (loss)							**(252)**	622

Capital Expenditures [1]

	Three Months Ended					
	Mar 31, 2015			Mar 31, 2014		
	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	**$ 44**	**$ (78)**	**$ (34)**	$ 100	$ (47)	$ 53
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa	**2**	**–**	**2**	17	–	17
	$ 46	**$ (78)**	**$ (32)**	$ 117	$ (47)	$ 70
Property, plant and equipment						
Exploration and Production						
North America	**$ 457**	**$ (5)**	**$ 452**	$ 987	$ (18)	$ 969
North Sea	**62**	**–**	**62**	88	–	88
Offshore Africa	**124**	**–**	**124**	–	–	–
	643	**(5)**	**638**	1,075	(18)	1,057
Oil Sands Mining and Upgrading [3]	**569**	**(4)**	**565**	579	(7)	572
Midstream	**3**	**–**	**3**	25	–	25
Head office	**7**	**–**	**7**	10	(1)	9
	$ 1,222	**$ (9)**	**$ 1,213**	$ 1,689	$ (26)	$ 1,663

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

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

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

Segmented Assets

	Total Assets	
	Mar 31 2015	Dec 31 2014
Exploration and Production		
North America	**$ 34,015**	$ 34,382
North Sea	**2,834**	2,711
Offshore Africa	**1,489**	1,214
Other	**51**	18
Oil Sands Mining and Upgrading	**21,078**	20,702
Midstream	**1,107**	1,048
Head office	**125**	125
	$ 60,699	$ 60,200

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

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

Interest coverage ratios for the twelve month period ended March 31, 2015:

Interest coverage (times)	
Net earnings (1)	7.4x
Cash flow from operations (2)	17.3x

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

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

Corporate Information

Board of Directors

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N. Murray Edwards, O.C.

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Honourable Gary A. Filmon, P.C., O.C., O.M.

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Ambassador Gordon D. Giffin

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Steve W. Laut

Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C.

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Officers

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Douglas A. Proll
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Chief Financial Officer and Senior Vice-President, Finance

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Senior Vice-President, Marketing

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

Darren M. Fichter
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Peter J. Janson
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Terry J. Jocksch
Senior Vice-President, Thermal

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Senior Vice-President, Production and Development Operations

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Senior Vice-President, Exploration

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Vice-President, Land

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Corporate Secretary

International Operations
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Aberdeen, Scotland

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Vice-President, Exploration, International

Barry Duncan
Vice-President, Finance, International

Andrew M. McBoyle
Vice-President, Exploitation, International

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

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

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