Canadian Natural

PRESS RELEASE

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2010 FIRST QUARTER RESULTS

CALGARY, ALBERTA – MAY 6, 2010 – FOR IMMEDIATE RELEASE

Commenting on first quarter results, Canadian Natural's Chairman, Allan Markin stated, "Overall it has been an excellent start to the year for Canadian Natural as production in North America and in our International operations are doing as or better than expected. We continue to focus on optimizing operational performance in all parts of the Company. Ramp up at Horizon continues with production at the high end of expectations as our team continues to work towards production at levels near targeted capacity of 110,000 barrels per day."

John Langille, Vice-Chairman of Canadian Natural continued, "Our financial position exiting the first quarter shows continued strengthening as the Company benefited from an increase in production and favorable heavy oil differentials. This has resulted in a reduction in outstanding debt and an improvement in our debt to book capital to 31%. Throughout 2010, we anticipate solid cash flow and earnings as we remain focused on our operational and financial discipline."

Steve Laut, President for Canadian Natural stated, "The Company continues to focus on short-, mid- and long-term strategies for the development of our product types to allocate capital effectively. The efforts of our committed and dedicated team of people to promote operational efficiencies have resulted in strong production volumes and a reduction in our conventional operating costs."

HIGHLIGHTS

	Three Months Ended		
($ millions, except as noted)	**Mar 31 2010**	Dec 31 2009	Mar 31 2009
Net earnings	**$ 866**	$ 455	$ 305
Per common share, basic and diluted	**$ 1.60**	$ 0.85	$ 0.56
Adjusted net earnings from operations (1)	**$ 658**	$ 667	$ 727
Per common share, basic and diluted	**$ 1.21**	$ 1.23	$ 1.34
Cash flow from operations (2)	**$ 1,505**	$ 1,703	$ 1,516
Per common share, basic and diluted	**$ 2.77**	$ 3.14	$ 2.80
Capital expenditures, net of dispositions	**$ 1,072**	$ 694	$ 1,256
Daily production, before royalties			
Natural gas (mmcf/d)	**1,226**	1,250	1,369
Crude oil and NGLs (bbl/d)	**406,266**	366,451	330,017
Equivalent production (boe/d)	**610,556**	574,857	558,142

(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 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.

HIGHLIGHTS

- Total crude oil and NGLs production for Q1/10 was 406,266 bbl/d, an increase of 11% from the previous quarter. Volumes in Q1/10 were at the high end of the Company's guidance of 372,000 to 409,000 bbl/d and reflect the cyclic nature of Primrose production and an increase in production at Horizon Oil Sands ("Horizon") from the last quarter.

- Natural gas production for Q1/10 averaged 1,226 mmcf/d, slightly above the Company's guidance of 1,197 to 1,221 mmcf/d due to continued operational optimization and good drilling results. Natural gas production for Q1/10 was down 2% from the previous quarter. The decrease in volumes for Q1/10 from previous quarters reflects the continuing reallocation of capital towards higher return crude oil projects.

- Quarterly cash flow from operations was $1.5 billion, a decrease of 12% from the previous quarter, and relatively flat from Q1/09. The decrease from Q4/09 reflects the impact of lower natural gas sales volumes, higher realized risk management expense, higher cash tax expense and the stronger Canadian dollar relative to the US dollar, partially offset by the impact of higher crude oil sales volumes, and higher realized pricing.

- Quarterly net earnings for Q1/10 of $866 million included the effects of unrealized risk management activities, fluctuations in foreign exchange rates, stock-based compensation and the impact of statutory tax rate and other legislative changes on future income tax liabilities. Excluding these items, quarterly adjusted net earnings from operations for Q1/10 were $658 million.

- Strong quarterly free cash flow and strengthening foreign exchange rates contributed to a reduction in long-term debt of over $700 million.

- Reliability at Horizon continues to improve. In both March and April 2010, synthetic crude oil ("SCO") production was in excess of 100,000 barrels per day.

- In the first quarter, Canadian Natural drilled 150 primary heavy crude oil wells as part of the planned record drilling program for 2010.

- Platform B of the Olowi Project was commissioned in Q1/10. Production at three wells commenced in early Q2/10.

- During the first quarter of 2010 and into the second quarter of 2010 Canadian Natural entered into a number of agreements to purchase crude oil and natural gas properties in its core regions in Western Canada aggregating approximately $1 billion. Subject to receipt of any required regulatory approvals and any applicable rights of first refusal, the majority of these acquisitions are expected to close in late Q2/10 and corporate guidance has been revised accordingly.

- In March 2010, the Government of Alberta modified the conventional crude oil and natural gas royalty rates. These changes will be effective on January 1, 2011. Additional changes to the Alberta Royalty Framework, including potential further changes to conventional crude oil and natural gas royalty curves are expected to be finalized and announced by May 31, 2010.

- Declared a quarterly cash dividend on common shares of $0.15 per common share payable July 1, 2010. The dividend will be adjusted to reflect the proposed split in the Company's shares.

- On March 3, 2010, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting to be held on May 6, 2010.

OPERATIONS REVIEW

Activity by core region

	Net undeveloped land as at Mar 31, 2010 (thousands of net acres)	Drilling activity Three Months Ended Mar 31, 2010 (net wells) [1]
North America conventional		
Northeast British Columbia	**1,972**	**14.1**
Northwest Alberta	**1,335**	**23.8**
Northern Plains	**5,869**	**256.3**
Southern Plains	**818**	**7.1**
Southeast Saskatchewan	**142**	**9.9**
Thermal In-situ Oil Sands	**488**	**173.0**
	10,624	**484.2**
Oil Sands Mining and Upgrading	**115**	**112.0**
North Sea	**150**	**-**
Offshore West Africa	**4,193**	**2.8**
	15,082	**599.0**

(1) Drilling activity includes stratigraphic test and service wells.

Drilling activity (number of wells)

	Three Months Ended Mar 31			
	2010		2009	
	Gross	**Net**	Gross	Net
Crude oil	**256**	**243**	94	93
Natural gas	**52**	**45**	87	64
Dry	**15**	**14**	16	15
Subtotal	**323**	**302**	197	172
Stratigraphic test / service wells	**298**	**297**	236	236
Total	**621**	**599**	433	408
Success rate (excluding stratigraphic test / service wells)		**95%**		91%

North America Conventional

North America natural gas

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Natural gas production (mmcf/d)	**1,193**	1,218	1,347
Net wells targeting natural gas	**49**	28	72
Net successful wells drilled	**45**	28	64
Success rate	**92%**	100%	89%

- Q1/10 North America natural gas production decreased, as expected, 11% from Q1/09 and 2% from Q4/09, reflecting the Company's strategic decision to reduce spending on natural gas drilling. Although natural gas production volumes have decreased from Q1/09, the Company has been able to maintain its unit of production operating costs as a result of the Company's continued focus on optimization.
- Canadian Natural targeted 49 net natural gas wells in Q1/10 with a prudent program across the Company's core regions. In Northeast British Columbia, 14 net natural gas wells were drilled, while in Northwest Alberta, 19 net natural gas wells were drilled. In the Northern Plains, 15 net natural gas wells were drilled, with 1 net natural gas well drilled in the Southern Plains.
- Planned drilling activity for Q2/10 includes 11 net natural gas wells.

North America crude oil and NGLs

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Crude oil and NGLs production (bbl/d)	**252,450**	229,206	253,833
Net wells targeting crude oil	**250**	212	97
Net successful wells drilled	**240**	195	90
Success rate	**96%**	92%	93%

- Q1/10 North America crude oil and NGLs production decreased 1% from Q1/09 and increased 10% from Q4/09 levels. The increase in production volume from Q4 was largely due to cyclic thermal crude oil at Primrose.
- At Primrose East, Canadian Natural continues to work with regulators and has commenced surveillance steaming with average production targeted to be between 16,000 bbl/d and 20,000 bbl/d in 2010. Canadian Natural plans to slowly return to normal steaming activities by late 2010 or early 2011.
- Canadian Natural is continuing its proposed third phase of the thermal growth plan with a development plan for the Kirby In-Situ Oil Sands Project. The Company has filed its formal regulatory application documents for this project and is awaiting regulatory approval. Final project scope and corporate sanction is targeted for late 2010.
- Improvements at Pelican Lake continue with conversion to polymer flooding. Pelican Lake production averaged approximately 37,000 bbl/d for Q1/10.
- Conventional heavy crude oil production volumes increased 5% in Q1/10 compared to Q4/09, reflecting the Company's record drilling program planned for 2010.
- During Q1/10, drilling activity targeted 250 net wells including 150 wells targeting heavy crude oil, 74 wells targeting Pelican Lake crude oil, and 26 wells targeting light crude oil.

- Planned drilling activity for Q2/10 includes 113 net crude oil wells, excluding stratigraphic test and service wells, compared to drilling activity for Q2/09 of 97 net crude oil wells, excluding stratigraphic test and service wells.

International

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Crude oil production (bbl/d)			
North Sea	**36,879**	34,408	42,369
Offshore West Africa	**29,942**	32,643	30,431
Natural gas production (mmcf/d)			
North Sea	**15**	12	10
Offshore West Africa	**18**	20	12
Net wells targeting crude oil	**2.8**	-	3.2
Net successful wells drilled	**2.8**	-	3.2
Success rate	**100%**	-	100%

North Sea

- North Sea crude oil production for the quarter increased by 7% from Q4/09. Production was at the high end of guidance and reflected strong well performance in the Ninian Field during the quarter.
- The Company recommenced platform drilling operations at the beginning of the second quarter and continues to focus on maturing and high grading its inventory of future drilling locations. The Company maintains focus on lowering costs.

Offshore West Africa

- Offshore West Africa's crude oil production decreased by 8% from Q4/09, reflecting a planned shutdown at Espoir associated with the facilities modules upgrade on the Espoir FPSO with ongoing construction targeted for completion in Q3/10.
- The Company is currently drilling the second platform (Platform B) at the Olowi Field, Offshore Gabon with 4 gross wells drilled and completed and first Platform B crude oil achieved in April 2010. Initial production performance from the first 3 wells is encouraging. The fourth well is scheduled to be brought on production in May 2010. Two additional wells are planned to be drilled on Platform B with Platform A drilling to follow.

Oil Sands Mining and Upgrading

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Synthetic crude oil production (bbl/d)	**86,995**	70,194	3,384

- The Company continues to move closer to sustainable production as SCO production was 86,995 bbl/d in Q1/10, an increase of 24% from Q4/09. Monthly average production for Horizon is now provided on a monthly basis on the Company's website.
- Plant challenges in Q4/09 such as downtime relating to a coker furnace were largely resolved in March 2010.
- Enhancement of operational procedures and plant reliability continues to remain a focus.

- Operational costs in the quarter averaged $43.12 per barrel of SCO primarily due to slightly lower production volumes in January, unplanned maintenance expenditures such as costs associated with the coker furnace repairs, higher property tax and the impact of changes in product inventory carrying costs in the quarter. The Company continues to target reduced operating costs between $31.00 to $37.00 per barrel of SCO for 2010. March 2010 actual operating costs were approximately $32.50 per barrel (including approximately $3.40 per barrel of natural gas input costs), in line with full year guidance.
- The Company continues to target stable production levels with annual production guidance for 2010 remaining at 90,000 to 105,000 barrels per day of SCO at Horizon. May 2010 production is expected to be between 75,000 to 80,000 barrels per day of SCO due to planned reductions in production levels for the month due to a planned maintenance outage which will slightly reduce May's volumes but are forecast to limit future operational issues and help reach and maintain sustained production levels.
- Engineering and procurement for Tranche 2 of the Phase 2/3 expansion is progressing with a focus on increasing reliability and uptime. Tranches 3 and 4 of Phase 2/3 continue to be re-profiled. The Company continues to work on completing its lessons learned from the construction of Phase 1 and implementing these into the development of future expansions.

MARKETING

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Crude oil and NGLs pricing			
WTI[1] benchmark price (US$/bbl)	**$ 78.79**	$ 76.17	$ 43.21
Western Canadian Select blend differential from WTI (%)	**12%**	16%	21%
SCO price (US$/bbl)	**$ 79.37**	$ 75.07	$ 44.97
Corporate average pricing before risk management[2] (C$/bbl)	**$ 68.76**	$ 68.00	$ 41.25
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 5.07**	$ 4.01	$ 5.34
Corporate average pricing before risk management (C$/mcf)	**$ 5.19**	$ 4.75	$ 5.46

(1) Refers to West Texas Intermediate (WTI) crude oil barrel priced at Cushing, Oklahoma.

(2) Excludes SCO.

- In Q1/10, the Western Canadian Select ("WCS") heavy crude oil differential as a percent of WTI was 12%, compared to 16% in Q4/09. Heavy crude oil differentials were narrow in Q1/10 as strong demand from the US continued for heavy crude oil.
- There is an active market for Horizon SCO and the Company has had success in selling the SCO to refiners in Edmonton and throughout North America.
- During Q1/10, the Company contributed approximately 161,000 bbl/d of its heavy crude oil streams to the WCS blend as market conditions resulted in optimal pricing for heavy crude oil.

FINANCIAL REVIEW

- The financial position of the Company remains robust and the Company continually examines its liquidity position and targets a low risk approach to finance. The implementation of its commodity hedging policy, its existing credit facilities and capital expenditure programs all support a flexible financial position:
  - A diverse asset base spread over various commodity types - produced in excess of 610,000 boe/d in Q1/10, with 95% of production located in G8 countries.
  - Financial stability and liquidity - cash flow from operations of $1.5 billion and free cash flow, net of capital expenditures, of over $400 million for Q1/10, with available unused bank lines of $2.5 billion at March 31, 2010.
  - Flexibility in asset base allowing for disciplined capital allocations.

- A strengthening balance sheet with debt to book capitalization of 31% and debt to EBITDA of 1.3 times, both below targeted ranges.
- Declared a quarterly cash dividend on common shares of C$0.15 per common share, payable July 1, 2010. The dividend will be adjusted to reflect the proposed split in the Company's shares.
- Implemented a normal course issuer bid for the period from April 6, 2010 to April 5, 2011 to purchase up to 13,581,970 common shares (2.5%) of the common shares outstanding at March 17, 2010. As at May 6, 2010, no common shares had been purchased for cancellation.
- On March 3, 2010, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting to be held on May 6, 2010. If the special resolution is passed and all regulatory approvals are obtained, the record date for determining shareholders entitled to participate in the subdivision is expected to be on or about May 21, 2010 and it is expected that the common shares will begin to trade on a subdivided basis on Toronto Stock Exchange on or about May 19, 2010 and on the New York Stock Exchange on or about May 28, 2010.

OUTLOOK

- The Company forecasts 2010 production levels before royalties to average between 1,202 and 1,269 mmcf/d of natural gas and between 405,000 and 450,000 bbl/d of crude oil and NGLs. Q2/10 production guidance before royalties is forecast to average between 1,207 and 1,232 mmcf/d of natural gas and between 394,000 and 426,000 bbl/d of crude oil and NGLs. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

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" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, production volumes, royalties, operating costs, capital expenditures 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 Horizon Oil Sands, Primrose East, Pelican Lake, Olowi Field (Offshore Gabon), and the Kirby Thermal Oil Sands Project 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 if 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 crude oil and natural gas 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 difficulties in mining, extracting or upgrading 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; 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, bitumen, 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 should circumstances or Management’s estimates or opinions change.

Management’s Discussion and Analysis

Management’s Discussion and Analysis 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, 2010 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2009.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The financial statements have been prepared in accordance with generally accepted accounting principles in Canada (“GAAP”). This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, and cash production costs. These financial measures are not defined by GAAP 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 GAAP, 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 GAAP, in the “Financial Highlights” section of this MD&A. The derivation of cash production costs is included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the “Liquidity and Capital Resources” section of this MD&A.

The calculation of barrels of oil equivalent (“boe”) is based on a conversion ratio of six thousand cubic feet (“mcf”) of natural gas to one barrel (“bbl”) of crude oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the wellhead.

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

The following discussion refers primarily to the Company’s financial results for the three months ended March 31, 2010 in relation to the comparable period in 2009 and the fourth quarter of 2009. The accompanying tables form an integral part of this MD&A. This MD&A is dated May 6, 2010. Additional information relating to the Company, including its amended Annual Information Form for the year ended December 31, 2009, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Revenue, before royalties	**$ 3,580**	$ 3,319	$ 2,186
Net earnings	**$ 866**	$ 455	$ 305
Per common share – basic and diluted	**$ 1.60**	$ 0.85	$ 0.56
Adjusted net earnings from operations (1)	**$ 658**	$ 667	$ 727
Per common share – basic and diluted	**$ 1.21**	$ 1.23	$ 1.34
Cash flow from operations (2)	**$ 1,505**	$ 1,703	$ 1,516
Per common share – basic and diluted	**$ 2.77**	$ 3.14	$ 2.80
Capital expenditures, net of dispositions	**$ 1,072**	$ 694	$ 1,256

(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" presented below lists 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" presented below lists 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 2010***	*Dec 31 2009*	*Mar 31 2009*
Net earnings as reported	***$ 866***	*$ 455*	*$ 305*
Stock-based compensation (recovery) expense, net of tax (a)(d)	***(2)***	*65*	*3*
Unrealized risk management (gain) loss, net of tax (b)	***(154)***	*224*	*320*
Unrealized foreign exchange (gain) loss, net of tax (c)	***(135)***	*(77)*	*118*
Effect of statutory tax rate and other legislative changes on future income tax liabilities (d)	***83***	*–*	*(19)*
Adjusted net earnings from operations	***$ 658***	*$ 667*	*$ 727*

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of the outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.

(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in 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.

(c) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, offset by the impact of cross currency swaps, and are recognized in net earnings.

(d) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted or enacted. During the first quarter of 2010, the Canadian Federal budget proposed changes to the taxation of stock options surrendered by employees for cash payments. As a result of the proposed changes, the Company anticipates that Canadian based employees will no longer surrender their options for cash payments, resulting in a loss of income tax deductions for the Company. The impact of this change was an $83 million charge to future income tax expense during the quarter. Income tax rate changes in the first quarter of 2009 resulted in a reduction of future income tax liabilities of approximately $19 million in North America.

Cash Flow from Operations

	Three Months Ended		
($ millions)	***Mar 31 2010***	*Dec 31 2009*	*Mar 31 2009*
Net earnings	***$ 866***	*$ 455*	*$ 305*
Non-cash items:			
Depletion, depreciation and amortization	***771***	*836*	*646*
Asset retirement obligation accretion	***26***	*23*	*19*
Stock-based compensation (recovery) expense	***(2)***	*87*	*4*
Unrealized risk management (gain) loss	***(208)***	*308*	*463*
Unrealized foreign exchange (gain) loss	***(150)***	*(88)*	*138*
Deferred petroleum revenue tax expense (recovery)	***7***	*7*	*(3)*
Future income tax expense (recovery)	***195***	*75*	*(56)*
Cash flow from operations	***$ 1,505***	*$ 1,703*	*$ 1,516*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the first quarter of 2010 were $866 million compared to $305 million for the first quarter of 2009 and $455 million for the prior quarter. Net earnings for the first quarter of 2010 included net unrealized after-tax income of $208 million related to the effects of risk management activities, fluctuations in foreign exchange rates and stock-based compensation, and the impact of statutory tax rate and other legislative changes on future income tax liabilities, compared to net unrealized after-tax expenses of $422 million for the first quarter of 2009 and net unrealized after-tax expenses of $212 million for the prior quarter. Excluding these items, adjusted net earnings from operations for the first quarter of 2010 were $658 million compared to $727 million for the first quarter of 2009 and $667 million for the prior quarter. The decrease in adjusted net earnings from the first quarter of 2009 was primarily due to the impact of lower natural gas sales volumes and realized pricing, higher royalty expense, and fluctuations in the effects of realized risk management activities, partially offset by the impact of higher crude oil sales volumes associated with Horizon and higher realized crude oil pricing.

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

Cash flow from operations for the first quarter of 2010 was $1,505 million compared to $1,516 million for the first quarter of 2009 and $1,703 million for the prior quarter. The decrease in cash flow from operations from the prior quarter was primarily due to the impact of lower natural gas sales volumes, higher royalty expense, higher production expense related to Horizon, higher cash taxes and the impact of realized risk management activities, partially offset by the impact of higher crude oil sales volumes associated with Horizon and higher realized pricing.

Total production before royalties for the first quarter of 2010 increased 9% to 610,556 boe/d from 558,142 boe/d for the first quarter of 2009 and 6% from 574,857 boe/d for the prior quarter. Total production for the first quarter of 2010 was within the Company's previously issued guidance.

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 2010**		Dec 31 2009		Sep 30 2009		Jun 30 2009
Revenue, before royalties	**$**	**3,580**	$	3,319	$	2,823	$	2,750
Net earnings	**$**	**866**	$	455	$	658	$	162
Net earnings per common share								
– Basic and diluted	**$**	**1.60**	$	0.85	$	1.21	$	0.30

($ millions, except per common share amounts)		Mar 31 2009		Dec 31 2008		Sep 30 2008		Jun 30 2008
Revenue, before royalties	$	2,186	$	2,511	$	4,583	$	5,112
Net earnings (loss)	$	305	$	1,770	$	2,835	$	(347)
Net earnings (loss) per common share								
– Basic and diluted	$	0.56	$	3.27	$	5.25	$	(0.65)

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

- **Crude oil pricing** – The impact of fluctuating demand and geopolitical uncertainties on worldwide benchmark pricing, and the fluctuations in the Heavy Crude Oil Differential from WTI ("Heavy Differential") in North America.
- **Natural gas pricing** – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production from the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the commencement and ramp up of operations at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore West Africa.
- **Natural gas sales volumes** – Declines in production due to the Company's strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates.
- **Production expense** – Fluctuations primarily due to the impact of the demand for services, industry-wide inflationary cost pressures experienced in prior quarters, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, and the commencement of operations at Horizon and the Olowi Field in Offshore Gabon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, proved reserves, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the commencement of operations at Horizon and the Olowi Field in Offshore Gabon, and the impact of an impairment at the Olowi Field at December 31, 2009.
- **Stock-based compensation** – Fluctuations due to the mark-to-market movements of the Company's stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company's share price.
- **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 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. The impact of unrealized foreign exchange gains and losses are recorded with respect to US dollar denominated debt and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swap hedges.
- **Income tax expense (recovery)** – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

(Quarterly Average)	Three Months Ended Mar 31 2010	Dec 31 2009	Mar 31 2009
WTI benchmark price (US$/bbl)	**$ 78.79**	$ 76.17	$ 43.21
Dated Brent benchmark price (US$/bbl)	**$ 76.32**	$ 74.54	$ 44.45
WCS blend differential from WTI (US$/bbl)	**$ 9.06**	$ 12.08	$ 8.98
WCS blend differential from WTI (%)	**12%**	16%	21%
SCO price (US$/bbl) (1)	**$ 79.37**	$ 75.07	$ 44.97
Condensate benchmark price (US$/bbl)	**$ 84.82**	$ 74.46	$ 43.44
NYMEX benchmark price (US$/mmbtu)	**$ 5.38**	$ 4.27	$ 4.87
AECO benchmark price (C$/GJ)	**$ 5.07**	$ 4.01	$ 5.34
US / Canadian dollar average exchange rate	**$ 0.9615**	$ 0.9468	$ 0.8028

(1) Synthetic Crude Oil ("SCO")

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$78.79 per bbl for the first quarter of 2010, an increase of 82% from US$43.21 per bbl for the first quarter of 2009, and 3% from US$76.17 per bbl for the prior quarter. WTI pricing was reflective of the overall balanced supply and demand environment, with strong Asian demand offsetting the demand decline related to the Organization of Economic Co-operation and Development (OECD).

Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Dated Brent ("Brent") pricing, which is more reflective of international markets and the overall supply and demand. Brent averaged US$76.32 per bbl for the first quarter of 2010, an increase of 72% compared to US$44.45 per bbl for the first quarter of 2009, and 2% from US$74.54 per bbl for the prior quarter.

The Western Canadian Select ("WCS") Heavy Differential averaged 12% for the first quarter of 2010, compared to 21% for the first quarter of 2009 and 16% for the prior quarter. The narrow Heavy Differential continued to reflect the relatively weak refinery margins.

The Company anticipates continued volatility in crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events, and the timing and extent of the near term economic recovery. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery margins.

NYMEX natural gas prices averaged US$5.38 per mmbtu for the first quarter of 2010, an increase of 10% from US$4.87 per mmbtu for the first quarter of 2009, and 26% from US$4.27 per mmbtu for the prior quarter. AECO natural gas prices for the first quarter of 2010 decreased 5% to average $5.07 per GJ from $5.34 per GJ in the first quarter of 2009, and increased 26% from $4.01 per GJ for the prior quarter. The weather patterns in the first quarter of 2010 resulted in stronger demand in the Northeast part of the United States and weaker demand in the Western part of North America, supporting a relatively higher pricing level over the last quarter. The stronger Canadian dollar negatively impacted the realized price at AECO in the first quarter of 2010 compared to the first quarter of 2009.

Update to Alberta Royalty Framework

On January 1, 2009, changes to the Alberta royalty regime under the Alberta Royalty Framework ("ARF") came into effect, including the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout, depending on benchmark crude oil pricing.

In addition, on January 1, 2009, new royalty formulas under the ARF for conventional crude oil and natural gas, specifying royalties on sliding scales ranging up to 50%, depending on commodity prices and well productivity, came into effect.

In March 2010, the Government of Alberta modified the conventional crude oil and natural gas royalty rates. These changes, effective January 1, 2011, include:

- A reduction in the maximum royalty rate to 5% on new natural gas and conventional crude oil wells for the first 12 months after the start of production, subject to volume limits of 500 mmcfe and 50,000 boe respectively.
- A reduction in the maximum royalty rate for conventional crude oil from 50% to 40% and a reduction in the maximum royalty rate for conventional and unconventional natural gas from 50% to 36%.

Additional changes to the ARF, including potential further changes to conventional crude oil and natural gas royalty curves, are expected to be finalized and announced by May 31, 2010.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Crude oil and NGLs (bbl/d)			
North America – Conventional	**252,450**	229,206	253,833
North America – Oil Sands Mining and Upgrading	**86,995**	70,194	3,384
North Sea	**36,879**	34,408	42,369
Offshore West Africa	**29,942**	32,643	30,431
	406,266	366,451	330,017
Natural gas (mmcf/d)			
North America	**1,193**	1,218	1,347
North Sea	**15**	12	10
Offshore West Africa	**18**	20	12
	1,226	1,250	1,369
Total barrels of oil equivalent (boe/d)	**610,556**	574,857	558,142
Product mix			
Light/medium crude oil and NGLs	**19%**	20%	22%
Pelican Lake crude oil	**6%**	7%	6%
Primary heavy crude oil	**15%**	15%	15%
Thermal heavy crude oil	**12%**	10%	15%
Synthetic crude oil	**14%**	12%	1%
Natural gas	**34%**	36%	41%
Percentage of gross revenue (1) (excluding midstream revenue)			
Crude oil and NGLs	**82%**	82%	64%
Natural gas	**18%**	18%	36%

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

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Crude oil and NGLs (bbl/d)			
North America – Conventional	**206,094**	195,070	224,506
North America – Oil Sands Mining and Upgrading	**83,918**	67,806	3,362
North Sea	**36,803**	34,341	42,265
Offshore West Africa	**28,927**	30,296	28,341
	355,742	327,513	298,474
Natural gas (mmcf/d)			
North America	**1,101**	1,135	1,180
North Sea	**15**	12	10
Offshore West Africa	**17**	19	11
	1,133	1,166	1,201
Total barrels of oil equivalent (boe/d)	**544,553**	521,894	498,740

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

Total crude oil and NGLs production for the first quarter of 2010 increased 23% to 406,266 bbl/d from 330,017 bbl/d for the first quarter of 2009, and 11% from 366,451 bbl/d for the prior quarter. The increase from the first quarter in 2009 was primarily due to the commencement of production from Horizon. The increase from the prior quarter was in line with expectations and primarily related to the cyclic nature of the Company's thermal production and increased Horizon production. Crude oil and NGLs production in the first quarter of 2010 was at the high end of the Company's previously issued guidance of 372,000 to 409,000 bbl/d.

Natural gas production for the first quarter of 2010 decreased 10% to 1,226 mmcf/d compared to 1,369 mmcf/d for the first quarter of 2009 and 2% from 1,250 mmcf/d for the prior quarter. The decrease in natural gas production from the comparable periods reflects the expected production declines due to the allocation of capital to higher return crude oil projects resulting in a strategic reduction of natural gas drilling activity. Natural gas production in the first quarter of 2010 exceeded the Company's previously issued guidance of 1,197 to 1,221 mmcf/d.

For 2010, annual production guidance is targeted to average between 405,000 and 450,000 bbl/d of crude oil and NGLs and between 1,202 and 1,269 mmcf/d of natural gas. Second quarter 2010 production guidance is targeted to average between 394,000 and 426,000 bbl/d of crude oil and NGLs and between 1,207 and 1,232 mmcf/d of natural gas.

North America – Conventional

First quarter North America conventional crude oil and NGLs production averaged 252,450 bbl/d, comparable to 253,833 bbl/d for the first quarter of 2009, and increased 10% from 229,206 bbl/d for the prior quarter. The fluctuations in crude oil and NGLs production was primarily due to the cyclic nature of the Company's thermal production and was in line with expectations. Production of conventional crude oil and NGLs exceeded the Company's previously issued guidance of 240,000 bbl/d to 250,000 bbl/d for the first quarter of 2010.

For the first quarter of 2010, natural gas production decreased 11% to 1,193 mmcf/d from 1,347 mmcf/d for the first quarter of 2009, and 2% from 1,218 mmcf/d for the prior quarter. The decreases in natural gas production were consistent with the Company's strategic decision to reduce natural gas drilling activity and allocate capital to higher return projects. Production of natural gas exceeded the Company's previously issued guidance of 1,165 mmcf/d to 1,185 mmcf/d for the first quarter of 2010.

North America – Oil Sands Mining and Upgrading

Horizon Phase 1 commenced production of synthetic crude oil during 2009. Production averaged 86,995 bbl/d for the first quarter of 2010, up 24% from 70,194 bbl/d in the prior quarter. Production volumes fluctuated throughout the quarter as the Company continued to focus on stabilizing and ramping up production. First quarter production for 2010 was at the high end of the Company's previously issued guidance of 70,000 bbl/d to 90,000 bbl/d.

North Sea

First quarter 2010 North Sea crude oil production decreased 13% to 36,879 bbl/d from 42,369 bbl/d for the first quarter of 2009 and increased 7% from 34,408 bbl/d for the prior quarter. Production in the first quarter of 2010 was at the high end of the Company's previously issued guidance of 34,000 bbl/d to 37,000 bbl/d primarily due to improved uptime and well performance from the Ninian Platforms.

Offshore West Africa

First quarter 2010 Offshore West Africa crude oil production decreased 2% to 29,942 bbl/d from 30,431 bbl/d for the first quarter of 2009, and 8% from 32,643 bbl/d for the prior quarter. Production in the first quarter was within the Company's previously issued guidance of 28,000 bbl/d to 32,000 bbl/d and was impacted by a planned shutdown at Espoir for installation of facilities upgrades.

The Company is currently drilling the second platform (Platform B) at the Olowi Field, Offshore Gabon with 3 gross wells drilled and completed and first Platform B crude oil achieved in April 2010.

Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized on crude oil volumes that were stored in various tanks, pipelines, or floating production, storage and offtake vessels, as follows:

(bbl)	**Mar 31 2010**	Dec 31 2009	Mar 31 2009
North America – Conventional	**761,351**	1,131,372	761,351
North America – Oil Sands Mining and Upgrading (SCO)	**1,021,028**	1,224,481	304,544
North Sea	**642,457**	713,112	1,305,169
Offshore West Africa[1]	**898,233**	51,103	373,103
	3,323,069	3,120,068	2,744,167

(1) March 31, 2009 inventory volumes include a one-time adjustment to sales volumes for MD&A reporting purposes only.

OPERATING HIGHLIGHTS – CONVENTIONAL

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Crude oil and NGLs ($/bbl) [1]			
Sales price [2]	**$ 68.76**	$ 68.00	$ 41.25
Royalties	**10.08**	7.96	3.98
Production expense	**14.56**	15.45	15.02
Netback	**$ 44.12**	$ 44.59	$ 22.25
Natural gas ($/mcf) [1]			
Sales price [2]	**$ 5.19**	$ 4.75	$ 5.46
Royalties [3]	**0.41**	0.35	0.72
Production expense	**1.20**	1.03	1.18
Netback	**$ 3.58**	$ 3.37	$ 3.56
Barrels of oil equivalent ($/boe) [1]			
Sales price [2]	**$ 53.88**	$ 51.95	$ 37.87
Royalties	**7.07**	5.60	4.14
Production expense	**11.67**	11.72	11.77
Netback	**$ 35.14**	$ 34.63	$ 21.96

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

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

(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

PRODUCT PRICES – CONVENTIONAL

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 66.18**	$ 65.12	$ 37.40
North Sea	**$ 80.53**	$ 78.89	$ 54.67
Offshore West Africa	**$ 79.30**	$ 72.88	$ 54.27
Company average	**$ 68.76**	$ 68.00	$ 41.25
Natural gas ($/mcf) (1) (2)			
North America	**$ 5.20**	$ 4.75	$ 5.46
North Sea	**$ 4.30**	$ 4.94	$ 4.28
Offshore West Africa	**$ 5.56**	$ 5.04	$ 6.68
Company average	**$ 5.19**	$ 4.75	$ 5.46
Company average ($/boe) (1) (2)	**$ 53.88**	$ 51.95	$ 37.87

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

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

North America

North America realized crude oil prices increased 77% to average $66.18 per bbl for the first quarter of 2010 from $37.40 per bbl for the first quarter of 2009, and 2% from $65.12 per bbl for the prior quarter. The increase from the comparable quarters was primarily a result of increased WTI benchmark pricing and the impact of the narrow Heavy Differential, partially offset by the impact of the stronger Canadian dollar relative to the US dollar.

The Company continues to focus on its crude oil marketing strategy, and in the first quarter of 2010 contributed approximately 161,000 bbl/d of heavy crude oil blends to the WCS stream.

In the first quarter of 2010, the Company announced, together with North West Upgrading Inc., the submission of a joint proposal to the Alberta Government to construct and operate a bitumen refinery near Redwater, Alberta. This proposal was submitted in response to a request for proposal under the Alberta Royalty Framework's Bitumen Royalty In Kind (BRIK) program. The Alberta Government is expected to announce the successful bid later in 2010.

North America realized natural gas prices decreased 5% to average $5.20 per mcf for the first quarter of 2010 from $5.46 per mcf for the first quarter of 2009, and increased 9% from $4.75 per mcf for the prior quarter. The decrease in natural gas prices from the first quarter of 2009 was primarily related to lower benchmark prices due to lower demand and high storage levels, and the impact of the stronger Canadian dollar relative to the US dollar. The increase in natural gas prices from the prior quarter was primarily related to seasonality of demand.

Comparisons of the prices received for the Company's North America conventional production by product type were as follows:

(Quarterly Average)	**Mar 31 2010**	Dec 31 2009	Mar 31 2009
Wellhead Price (1) (2)			
Light/medium crude oil and NGLs ($/bbl)	**$ 72.15**	$ 67.30	$ 45.97
Pelican Lake crude oil ($/bbl)	**$ 66.04**	$ 63.75	$ 37.50
Primary heavy crude oil ($/bbl)	**$ 66.45**	$ 65.46	$ 37.99
Thermal heavy crude oil ($/bbl)	**$ 62.08**	$ 63.62	$ 31.53
Natural gas ($/mcf)	**$ 5.20**	$ 4.75	$ 5.46

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

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

North Sea

North Sea realized crude oil prices increased 47% to average $80.53 per bbl for the first quarter of 2010 from $54.67 per bbl for the first quarter of 2009, and 2% from $78.89 per bbl for the prior quarter. The increase in realized crude oil prices in the North Sea from the prior periods was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 46% to average $79.30 per bbl for the first quarter of 2010 from $54.27 per bbl for the first quarter of 2009, and 9% from $72.88 per bbl for the prior quarter. The increase in realized crude oil prices in Offshore West Africa from the prior periods was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar. Realized crude oil prices in Offshore West Africa were also impacted by the timing of liftings from each field.

ROYALTIES – CONVENTIONAL

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 12.13**	$ 9.88	$ 4.54
North Sea	**$ 0.17**	$ 0.15	$ 0.13
Offshore West Africa	**$ 2.69**	$ 5.24	$ 3.73
Company average	**$ 10.08**	$ 7.96	$ 3.98
Natural gas ($/mcf) (1)			
North America (2)	**$ 0.41**	$ 0.35	$ 0.73
Offshore West Africa	**$ 0.19**	$ 0.27	$ 0.46
Company average	**$ 0.41**	$ 0.35	$ 0.72
Company average ($/boe) (1)	**$ 7.07**	$ 5.60	$ 4.14
Percentage of revenue (3)			
Crude oil and NGLs	**15%**	12%	10%
Natural gas (2)	**8%**	7%	13%
Boe	**13%**	11%	11%

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

(2) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

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

North America

North America royalties for the three months ended March 31, 2010 compared to 2009 reflect stronger realized commodity prices and the impact of the changes under the ARF.

Crude oil and NGLs royalties averaged approximately 18% of revenues for the first quarter of 2010, compared to 12% for the first quarter in 2009 and 15% for the prior quarter. Crude oil and NGLs royalties per bbl are anticipated to average 17% to 19% of gross revenue for 2010.

Natural gas royalties averaged approximately 8% of revenues for the first quarter of 2010 compared to 13% for the first quarter of 2009 and 7% for the prior quarter. The decrease in natural gas royalty rates for the first quarter of 2010 compared to the prior year was due to the impact of low natural gas benchmark pricing. Natural gas royalties are anticipated to average 6% to 8% of gross revenue for 2010.

Offshore West Africa

Under the terms of the Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of revenue averaged approximately 3% for the first quarter of 2010 compared to 7% for the first quarter of 2009 and the prior quarter. Offshore West Africa royalty rates are anticipated to average 7% to 9% of gross revenue for 2010.

PRODUCTION EXPENSE – CONVENTIONAL

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 13.09**	$ 13.44	$ 14.60
North Sea	**$ 25.15**	$ 27.03	$ 22.39
Offshore West Africa	**$ 13.49**	$ 15.26	$ 11.39
Company average	**$ 14.56**	$ 15.45	$ 15.02
Natural gas ($/mcf) [1]			
North America	**$ 1.17**	$ 1.01	$ 1.17
North Sea	**$ 3.54**	$ 3.23	$ 1.86
Offshore West Africa	**$ 1.63**	$ 0.70	$ 1.70
Company average	**$ 1.20**	$ 1.03	$ 1.18
Company average ($/boe) [1]	**$ 11.67**	$ 11.72	$ 11.77

(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 2010 decreased 10% to $13.09 per bbl from $14.60 per bbl for the first quarter of 2009 and 3% from $13.44 per bbl for the prior quarter. The decrease in production expense per barrel for the first quarter of 2010 was a result of the Company's focus on optimizing service costs, together with lower power prices and cost of natural gas used for fuel. North America crude oil and NGLs production expense is anticipated to average $13.00 to $14.00 per bbl for 2010.

North America natural gas production expense for the first quarter of 2010 averaged $1.17 per mcf and was comparable to the first quarter of 2009 and increased 16% from $1.01 per mcf for the prior quarter. The increase in production expense per mcf from the prior quarter was primarily a result of the impact of normal seasonal costs associated with winter access and colder weather and lower production volumes on fixed costs. The Company continues to focus on optimizing service costs. North America natural gas production expense is anticipated to average $1.15 to $1.25 per mcf for 2010.

North Sea

North Sea crude oil production expense increased on a per barrel basis from the prior year due to lower production volumes on a relatively fixed operating cost base. North Sea crude oil production expense decreased on a per barrel basis from the prior quarter due to lower maintenance activities and improved performance from the Ninian Platforms. Production expense for the first quarter of 2010 reflected the Company's ongoing focus on lowering costs. Production expense is anticipated to average $31.00 to $35.00 per bbl for 2010.

Offshore West Africa

Offshore West Africa crude oil production expense increased from the prior year on a per barrel basis due to the timing of liftings of each field, and higher operating costs associated with Gabon coming on stream in 2009. Offshore West Africa crude oil production expense decreased from the prior quarter on a per barrel basis due to the timing of liftings of each field. Production expense is anticipated to average $14.00 to $17.00 per bbl for 2010.

DEPLETION, DEPRECIATION AND AMORTIZATION – CONVENTIONAL

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Expense ($ millions)	**$ 679**	$ 754	$ 661
$/boe [1]	**$ 14.52**	$ 15.68	$ 13.21

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

The increase in Depletion, Depreciation and Amortization expense from the previous year was due to the increase in the estimated future costs to develop the Company's proved undeveloped reserves in the North Sea. The decrease in Conventional Depletion, Depreciation and Amortization expense from the prior quarter was primarily due to the impact of an impairment related to Gabon, Offshore West Africa recorded in the fourth quarter of 2009, offset by the impact of higher production.

ASSET RETIREMENT OBLIGATION ACCRETION – CONVENTIONAL

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Expense ($ millions)	**$ 20**	$ 17	$ 17
$/boe [1]	**$ 0.43**	$ 0.36	$ 0.35

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

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

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

FINANCIAL METRICS

	Three Months Ended		
($/bbl) [1]	**Mar 31 2010**	Dec 31 2009	Mar 31 2009
SCO sales price [2]	**$ 78.76**	$ 76.33	$ –
Bitumen value for royalty purposes [3]	**$ 61.33**	$ 58.90	$ –
Bitumen royalties [4]	**$ 2.83**	$ 3.06	$ –

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

(2) Net of transportation.

(3) Calculated as the simple average of the monthly bitumen valuation methodology price.

(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

The increase in SCO price from the previous quarter was due to the increase in WTI price. There is an active market for SCO throughout North America.

PRODUCTION COSTS

The following tables provide reconciliations of Oil Sands Mining and Upgrading production costs to the Segmented Information disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

($ millions)	Three Months Ended Mar 31 2010	Dec 31 2009	Mar 31 2009
Cash costs, excluding natural gas costs	**$ 299**	$ 228	$ –
Natural gas costs	**47**	31	–
Total cash production costs	**$ 346**	$ 259	$ –

($/bbl) (1)	Three Months Ended Mar 31 2010	Dec 31 2009	Mar 31 2009
Cash costs, excluding natural gas costs	**$ 37.29**	$ 36.23	$ –
Natural gas costs	**5.83**	4.98	–
Total cash production costs	**$ 43.12**	$ 41.21	$ –
Sales (bbl/d)	**89,256**	68,140	–

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

First sales from Horizon occurred in the second quarter of 2009.

Total cash production costs averaged $43.12 per bbl in the first quarter of 2010 compared to $41.21 per bbl for the fourth quarter of 2009. The increase in cash production costs was primarily due to unplanned maintenance activities including costs associated with the coker furnace repairs, increased property taxes and the impact of changes in product inventory carrying costs in the quarter. As production volumes are targeted to stabilize throughout 2010, cash production costs are expected to decrease in line with the previously issued annual guidance of $31.00 to $37.00 per bbl for 2010.

($ millions)	Three Months Ended Mar 31 2010	Dec 31 2009	Mar 31 2009
Depreciation, depletion and amortization	**$ 90**	$ 83	$ 2
Asset retirement obligation accretion	**6**	6	2
Total	**$ 96**	$ 89	$ 4

($/bbl) (1)	Three Months Ended Mar 31 2010	Dec 31 2009	Mar 31 2009
Depreciation, depletion and amortization	**$ 11.22**	$ 13.28	$ –
Asset retirement obligation accretion	**0.69**	1.00	–
Total	**$ 11.91**	$ 14.28	$ –

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

Depletion, depreciation and amortization per barrel decreased in the first quarter of 2010, due to the impact of increased production on the component of depreciation determined on a straight-line basis.

MIDSTREAM

($ millions)	Three Months Ended **Mar 31 2010**	Dec 31 2009	Mar 31 2009
Revenue	**$ 19**	$ 18	$ 19
Production expense	**5**	5	5
Midstream cash flow	**14**	13	14
Depreciation	**2**	3	2
Segment earnings before taxes	**$ 12**	$ 10	$ 12

Midstream operating results were consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended **Mar 31 2010**	Dec 31 2009	Mar 31 2009
Expense ($ millions)	**$ 54**	$ 49	$ 47
$/boe (1)	**$ 0.99**	$ 0.92	$ 0.95

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

Administration expense for the first quarter of 2010 increased from the comparative quarters due to higher staffing related costs.

STOCK-BASED COMPENSATION EXPENSE

	Three Months Ended		
($ millions)	**Mar 31 2010**	Dec 31 2009	Mar 31 2009
(Recovery) expense	**$ (2)**	$ 87	$ 4

The Company recorded a $2 million ($2 million after-tax) stock-based compensation recovery for the three months ended March 31, 2010 primarily as a result of normal course graded vesting of options granted in prior periods, the impact of vested options exercised or surrendered during the period, and a 1% decrease in the Company's share price (Company's share price as at: March 31, 2010 – $75.17; December 31, 2009 – $76.00; March 31, 2009 – $48.91; December 31, 2008 – $48.75). For the three months ended March 31, 2010, the Company capitalized $2 million in stock-based compensation to Oil Sands Mining and Upgrading (March 31, 2009 – $9 million recovery). The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on March 31, 2010.

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to receive common shares or a direct cash payment in exchange for options surrendered. As a result of recently proposed changes to Canadian income tax legislation related to the cash surrender of options, the Company anticipates that Canadian based employees will now choose to exercise their options to receive newly issued common shares rather than surrender their options for cash payment.

For the three months ended March 31, 2010, the Company paid $36 million for stock options surrendered for cash settlement (March 31, 2009 – $28 million).

INTEREST EXPENSE

	Three Months Ended		
($ millions, except per boe amounts)	**Mar 31 2010**	Dec 31 2009	Mar 31 2009
Expense, gross	**$ 118**	$ 119	$ 143
Less: capitalized interest, Oil Sands Mining and Upgrading	**7**	8	86
Expense, net	**$ 111**	$ 111	$ 57
$/boe (1)	**$ 2.02**	$ 2.06	$ 1.14
Average effective interest rate	**4.7%**	4.5%	4.4%

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

Gross interest expense decreased from the comparable periods in 2009 primarily due to lower variable interest rates and debt levels, and reflected the impact of fluctuations in foreign exchange rates on US dollar denominated debt. The Company's average effective interest rate increased from the comparable periods in 2009 primarily due to increased weighting of fixed versus floating rate debt, partially offset by lower variable interest rates.

During the first quarter of 2009, interest capitalization ceased on Horizon Phase 1 as the Phase 1 assets were completed and available for their intended use, increasing net interest expense accordingly.

RISK MANAGEMENT ACTIVITIES

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

($ millions)	Three Months Ended **Mar 31 2010**	Dec 31 2009	Mar 31 2009
Crude oil and NGLs financial instruments	**$ 17**	$ (148)	$ (585)
Natural gas financial instruments	**(18)**	–	(32)
Foreign currency contracts and interest rate swaps	**40**	26	(24)
Realized loss (gain)	**$ 39**	$ (122)	$ (641)
Crude oil and NGLs financial instruments	**$ (73)**	$ 328	$ 483
Natural gas financial instruments	**(130)**	(17)	(24)
Foreign currency contracts and interest rate swaps	**(5)**	(3)	4
Unrealized (gain) loss	**$ (208)**	$ 308	$ 463
Net (gain) loss	**$ (169)**	$ 186	$ (178)

Complete details related to outstanding derivative financial instruments at March 31, 2010 are disclosed in note 11 to the Company's unaudited interim consolidated financial statements.

Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized gain of $208 million ($154 million after-tax) on its risk management activities for the three months ended March 31, 2010 (December 31, 2009 – unrealized loss of $308 million, $224 million after-tax; March 31, 2009 – unrealized loss of $463 million, $320 million after-tax).

FOREIGN EXCHANGE

($ millions)	Three Months Ended **Mar 31 2010**	Dec 31 2009	Mar 31 2009
Net realized (gain) loss	**$ (10)**	$ 4	$ (15)
Net unrealized (gain) loss [1]	**(150)**	(88)	138
Net (gain) loss	**$ (160)**	$ (84)	$ 123

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

The net unrealized foreign exchange gain for the three months ended March 31, 2010 was primarily due to the strengthening Canadian dollar with respect to the US dollar debt, and the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling. The net unrealized (gain) loss for the respective periods was partially offset by the cross currency swaps (three months ended March 31, 2010 – unrealized loss of $59 million; December 31, 2009 – unrealized loss of $48 million, three months ended March 31, 2009 – unrealized gain of $68 million). The net realized foreign exchange gain for the three months ended March 31, 2010 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the first quarter at US$0.9846 (December 31, 2009 – US$0.9555; March 31, 2009 – US$0.7935).

TAXES

($ millions, except income tax rates)	Three Months Ended **Mar 31 2010**	Dec 31 2009	Mar 31 2009
Current	**$ 32**	$ 25	$ 7
Deferred	**7**	7	(3)
Taxes other than income tax	**$ 39**	$ 32	$ 4
North America (1)	**$ 129**	$ 11	$ 5
North Sea	**53**	60	98
Offshore West Africa	**6**	23	14
Current income tax	**188**	94	117
Future income tax expense (recovery)	**195**	75	(56)
	383	169	61
Income tax rate and other legislative changes (2)	**(83)**	–	19
	$ 300	$ 169	$ 80
Effective income tax rate on adjusted net earnings from operations	**26.0%**	28.4%	25.1%

(1) Includes North America Conventional Crude Oil and Natural Gas, Midstream, and Oil Sands Mining and Upgrading segments.

(2) During the first quarter of 2010, the Canadian Federal budget proposed changes to the taxation of stock options surrendered by employees for cash payments. As a result of the proposed changes, the Company anticipates that Canadian based employees will no longer surrender their options for cash payments, resulting in a loss of income tax deductions for the Company. The impact of this change was an $83 million charge to future income tax expense during the quarter. Income tax rate changes in the first quarter of 2009 include the effect of a recovery of $19 million due to British Columbia corporate income tax rate reductions substantively enacted or enacted.

Taxes other than income tax primarily includes current and deferred Petroleum Revenue Tax (“PRT”), which is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including related capital and abandonment expenditures.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

For 2010, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense in Canada of $450 million to $550 million and in the North Sea and Offshore West Africa of $220 million to $260 million.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Mar 31 2010**	Dec 31 2009	Mar 31 2009
Expenditures on property, plant and equipment			
Net property acquisitions (dispositions)	**$ 36**	$ 11	$ 27
Land acquisition and retention	**38**	28	13
Seismic evaluations	**33**	13	28
Well drilling, completion and equipping	**442**	291	498
Production and related facilities	**382**	222	290
Total net reserve replacement expenditures	**931**	565	856
Oil Sands Mining and Upgrading:			
Horizon Phase 1 construction costs	**–**	–	128
Horizon Phase 1 commissioning and other costs	**–**	–	156
Horizon Phases 2/3 construction costs	**71**	42	19
Capitalized interest, stock-based compensation and other	**9**	12	79
Sustaining capital	**18**	53	–
Total Oil Sands Mining and Upgrading [2]	**98**	107	382
Midstream	**–**	1	5
Abandonments [3]	**39**	17	9
Head office	**4**	4	4
Total net capital expenditures	**$ 1,072**	$ 694	$ 1,256
By segment			
North America	**$ 809**	$ 436	$ 599
North Sea	**23**	48	42
Offshore West Africa	**99**	80	215
Other	**–**	1	–
Oil Sands Mining and Upgrading	**98**	107	382
Midstream	**–**	1	5
Abandonments [3]	**39**	17	9
Head office	**4**	4	4
Total	**$ 1,072**	$ 694	$ 1,256

(1) The net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.
(2) Net expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.
(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core regions where it can dominate the land base and infrastructure. 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 dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for the three months ended March 31, 2010 were $1,072 million compared to $1,256 million for the three months ended March 31, 2009. The decrease in capital expenditures from the prior year reflects the completion of Horizon Phase 1 construction in 2009.

Drilling Activity (number of wells)

	Three Months Ended		
	Mar 31 2010	Dec 31 2009	Mar 31 2009
Net successful natural gas wells	**45**	28	64
Net successful crude oil wells	**243**	195	93
Dry wells	**14**	17	15
Stratigraphic test / service wells	**297**	80	236
Total	**599**	320	408
Success rate (excluding stratigraphic test / service wells)	**95%**	93%	91%

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 79% of the total capital expenditures for the three months ended March 31, 2010 compared to approximately 49% for the three months ended March 31, 2009.

During the first quarter of 2010, the Company targeted 49 net natural gas wells, including 14 wells in Northeast British Columbia, 15 wells in the Northern Plains region, 19 wells in Northwest Alberta, and 1 well in the Southern Plains region. The Company also targeted 250 net crude oil wells. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 150 heavy crude oil wells, 74 Pelican Lake crude oil wells, and 7 light crude oil wells were drilled. Another 19 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company has entered into a number of agreements to purchase crude oil and natural gas properties in its core regions in Western Canada aggregating approximately $1 billion. Subject to receipt of any required regulatory approvals and any applicable rights of first refusal, the majority of these acquisitions are expected to close late in the second quarter of 2010, and corporate guidance has been revised accordingly.

As part of the phased expansion of its In-Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. Overall Primrose thermal production for the first quarter of 2010 averaged approximately 76,000 bbl/d, compared to approximately 82,000 bbl/d for the first quarter of 2009 and approximately 57,000 bbl/d for the prior quarter. The Primrose East expansion was completed and first steaming commenced in September 2008, with first production achieved in the first quarter of 2009. During the first quarter of 2009, operational issues on one of the pads caused steaming to cease on all well pads in the Primrose East project area. The Company is continuing to work with regulators to commence normal steaming.

The next planned phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby Project. Final project scope and corporate sanction is targeted for late 2010. Currently the Company is proceeding with the detailed engineering and design work.

Development of new pads and tertiary recovery conversion projects at Pelican Lake continued as expected throughout the first quarter of 2010. Drilling included 28 horizontal wells in the first quarter. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 37,000 bbl/d for the first quarter of 2010, consistent with the first quarter of 2009 and 38,000 bbl/day for the prior quarter.

For the second quarter of 2010, the Company's overall planned drilling activity in North America is expected to be comprised of 11 natural gas wells and 113 crude oil wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Limited Phase 2/3 spending during the quarter was focused on the construction of the third Ore Preparation Plant, the Mine Maintenance Shop and additional product tankage.

North Sea

In the first quarter of 2010, the Company continued preparation for platform drilling, which commenced as planned in April. The Company continues to focus on developing and high grading its inventory of drilling locations for future execution.

Offshore West Africa

During the first quarter of 2010, 2.8 net crude oil wells were drilled on Platform B at Olowi. Final commissioning of Platform B was completed and first crude oil production was achieved in April 2010. Drilling continues on Platform B and development activities are proceeding on the third platform (Platform A).

At Espoir the lift of the facilities upgrade modules onto the FPSO was completed on schedule and work continues towards completion of the upgrade in the second quarter, with associated production uplift anticipated in the third quarter of 2010. Also in the second quarter of 2010, the Company will be conducting a planned maintenance shutdown and the upgrade on the Espoir FPSO.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Mar 31 2010**		Dec 31 2009		Mar 31 2009
Working capital (deficit) (1)	**$**	**(534)**	$	(514)	$	237
Long-term debt (2) (3)	**$**	**8,939**	$	9,658	$	13,132
Share capital	**$**	**2,939**	$	2,834	$	2,809
Retained earnings		**17,481**		16,696		15,592
Accumulated other comprehensive (loss) income		**(152)**		(104)		315
Shareholders' equity	**$**	**20,268**	$	19,426	$	18,716
Debt to book capitalization (3) (4)		**31%**		33%		41%
Debt to market capitalization (3) (5)		**18%**		19%		33%
After tax return on average common shareholders' equity (6)		**11%**		8%		28%
After tax return on average capital employed (3) (7)		**8%**		6%		17%

(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 (March 31, 2010 – $nil; December 31, 2009 – $nil; March 31, 2009 – $205 million).

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

At March 31, 2010, 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 is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's December 31, 2009 annual MD&A**.** The Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon these factors, as well as 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 on-going 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.

At March 31, 2010, the Company had $2,516 million of available credit under its bank credit facilities. The Company's current debt ratings are BBB (high) with a stable trend by DBRS Limited, Baa2 with a stable outlook by Moody's Investors Service, Inc., and BBB with a stable outlook by Standard & Poor's Corporation.

Further details related to the Company's long-term debt at March 31, 2010 are discussed in note 4 to the Company's unaudited interim consolidated financial statements.

Long-term debt was $8,939 million at March 31, 2010, resulting in a debt to book capitalization ratio of 31% (December 31, 2009 – 33%; March 31, 2009 – 41%). This ratio is below the 35% to 45% range targeted by management. The Company remains committed to maintaining a strong balance sheet and flexible capital structure. The Company has hedged a portion of its crude oil and natural gas production for 2010 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program 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 program, the purchase of put options is in addition to the above parameters. As at March 31, 2010, in accordance with the policy, approximately 34% of budgeted crude oil volumes and approximately 39% of budgeted natural gas volumes were hedged using collars for the remainder of 2010.

Further details related to the Company's commodity related derivative financial instruments outstanding at March 31, 2010 are discussed in note 11 to the Company's unaudited interim consolidated financial statements.

Share capital

As at March 31, 2010, there were 543,762,000 common shares outstanding and 29,823,000 stock options outstanding. As at May 5, 2010, the Company had 544,350,000 common shares outstanding and 29,067,000 stock options outstanding.

On March 3, 2010, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.60 per common share for 2010. The increase represented a 43% increase from 2009, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), during the 12 month period commencing April 6, 2010 and ending April 5, 2011, up to 13,581,970 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. As at May 6, 2010, no common shares had been purchased for cancellation.

Share split

On March 3, 2010, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 6, 2010. If the special resolution is passed and all regulatory approvals are obtained, the record date for determining shareholders entitled to participate in the subdivision is expected to be on or about May 21, 2010, and it is expected that the common shares will begin to trade on a subdivided basis on the TSX on or about May 19, 2010 and on the NYSE on or about May 28, 2010.

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. As at March 31, 2010, no entities were consolidated under the Canadian Institute of Chartered Accountants Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at March 31, 2010:

($ millions)	Remaining 2010	2011	2012	2013	2014	Thereafter
Product transportation and pipeline	$ 160	$ 172	$ 144	$ 134	$ 135	$ 1,060
Offshore equipment operating leases	$ 116	$ 121	$ 100	$ 98	$ 98	$ 254
Offshore drilling	$ 34	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 12	$ 20	$ 21	$ 31	$ 39	$ 6,423
Long-term debt (2)	$ 400	$ 406	$ 355	$ 806	$ 355	$ 5,276
Interest expense (3)	$ 316	$ 435	$ 400	$ 360	$ 340	$ 4,627
Office leases	$ 19	$ 19	$ 3	$ 2	$ 2	$ 2
Other	$ 211	$ 65	$ 19	$ 14	$ 12	$ 33

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2010 – 2014 represent the estimated minimum expenditures required to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,369 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash 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, 2010.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions. 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.

CRITICAL ACCOUNTING ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

The preparation of financial statements requires the Company to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Actual results could differ from those estimates. A comprehensive discussion of the Company's significant accounting policies is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2009.

For the impact of new accounting standards, refer to note 2 of the unaudited interim consolidated financial statements as at March 31, 2010.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board ("IASB") in place of Canadian GAAP effective January 1, 2011.

The Company has established a formal IFRS project governance structure. The structure includes a Steering Committee, which consists of senior levels of management from finance and accounting, operations and information technology ("IT"). The Steering Committee provides regular updates to the Company's Management and the Audit Committee of the Board of Directors.

The Company's IFRS conversion project has been broken down into the following phases:

- Phase 1 Diagnostic – identification of potential accounting and reporting differences between Canadian GAAP and IFRS.
- Phase 2 Planning – establishment of project governance, processes, resources, budget and timeline.
- Phase 3 Policy Delivery and Documentation – establishment of accounting policies under IFRS.
- Phase 4 Policy Implementation – establishment of processes for accounting and reporting, IT change requirements, and education.
- Phase 5 Sustainment –ongoing compliance with IFRS after implementation.

The Company has completed the Diagnostic and Planning phases (Phases 1 and 2). Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, capitalized interest, impairment testing, and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. The Company is finalizing the necessary research to develop and document IFRS policies to address the major differences noted (Phase 3). A summary of the significant differences identified is included below. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable. In addition, certain IFRS standards are expected to change prior to adoption in 2011, and the impact of these potential changes is not known.

The Company has identified, developed and tested system processes and changes required to capture data required for IFRS accounting and reporting (Phase 4), including 2010 requirements to capture both Canadian GAAP and IFRS data. IT system changes are substantially complete and implemented as at March 31, 2010.

Summary of Identified IFRS Accounting Policy Differences

Property, Plant & Equipment

Adoption of IFRS will significantly impact the Company's accounting policies for PP&E. For Canadian GAAP purposes, the Company follows the full cost method of accounting for its conventional crude oil and natural gas properties and equipment as prescribed by Accounting Guideline 16 ("AcG16). Application of the full cost method of accounting is discussed in the "Critical Accounting Estimates" section of the 2009 annual MD&A. Significant differences in accounting for PP&E under IFRS include:

- Pre-exploration costs must be expensed. Under full cost accounting, these costs are currently included in the country cost centre.
- Exploration and evaluation costs will be initially capitalized as exploration and evaluation assets. Once technical feasibility and commercial viability of reserves is established for an area, the costs will be transferred to PP&E. If technically feasible and commercially viable reserves are not established for a new area, the costs must be expensed. Under full cost accounting, exploration and evaluation costs are currently disclosed as PP&E but withheld from depletion. Costs are transferred to the depletable assets when proved reserves are assigned or when it is determined that the costs are impaired.
- PP&E for producing properties will be depreciated at an asset level. Under full cost accounting, PP&E is depleted on a country cost centre basis.
- Interest directly attributable to the acquisition or construction of a qualifying asset must be capitalized to the cost of the asset. Under Canadian GAAP, capitalization of interest is not required.
- Impairment of PP&E will be tested at a cash generating unit level (the lowest level at which cash inflows can be separately identified). Under full cost accounting, impairment is tested at the country cost centre level.

IFRS 1 "First-time Adoption of International Financial Reporting Standards" issued by the IASB includes a transition exemption for oil and gas companies following full cost accounting under their previous GAAP. The transition exemption allows full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes to IFRS compliant units of account without requiring retroactive adjustment, subject to an initial impairment test. The Company intends to adopt this transition exemption. After initial adoption, future impairment charges may be reversed.

Asset Retirement Obligations

Canadian GAAP accounting requirements for asset retirement obligations (“ARO”) are discussed in the “Critical Accounting Estimates” section of the 2009 annual MD&A. A significant difference in accounting for ARO under IFRS is that the liability must be re-measured at each balance sheet date using the current discount rates, whereas under Canadian GAAP the discount rates do not change once the liability is recorded. On transition to IFRS, the change in ARO liability on PP&E for which the full cost exemption above is applied must be recorded in retained earnings. For the change in ARO liability on other non-full cost PP&E, the change will be adjusted to PP&E in accordance with the general exemption for decommissioning liabilities included in IFRS 1. In future periods, the impact of changes in discount rates on the ARO liability for all PP&E is adjusted to PP&E.

Stock-based Compensation

Under Canadian GAAP, the Company’s stock option plan liability is valued using the intrinsic value method, calculated as the amount by which the market price of the Company’s shares exceeds the exercise price of the option for vested options. Under IFRS, the stock option plan liability must be measured using a fair value option pricing model such as the Black-Scholes model. The Company intends to utilize the exemption in IFRS 1 under which options that were settled prior to January 1, 2010 will not have to be retrospectively restated.

Income Taxes

Both Canadian GAAP and IFRS follow the liability method of accounting for income taxes, where tax liabilities and assets are recognized on temporary differences. However, there are certain exceptions to the treatment of temporary differences under IFRS that may result in an adjustment to the Company’s future tax liability under IFRS. In addition, the Company’s future tax liability will be impacted by the tax effects of any changes noted in the above areas.

Other IFRS 1 Exemptions

The Company also intends to adopt the following IFRS 1 transition exemptions:

- The Company intends to elect to reset the foreign currency translation adjustment to zero by transferring the Canadian GAAP balance to retained earnings on January 1, 2010, rather than retrospectively restating the balance.
- The Company intends to adopt the IFRS 1 election to not restate business combinations entered into prior to January 1, 2010.

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the first quarter of 2010, excluding mark-to-market gains (losses) on risk management activities, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl (1)				
Excluding financial derivatives	$ 112	$ 0.21	$ 91	$ 0.17
Including financial derivatives	$ 98	$ 0.18	$ 81	$ 0.15
Natural gas – AECO C$0.10/mcf (1)				
Excluding financial derivatives	$ 31	$ 0.06	$ 23	$ 0.04
Including financial derivatives	$ 26	$ 0.05	$ 19	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 161	$ 0.30	$ 104	$ 0.19
Natural gas – 10 mmcf/d	$ 13	$ 0.02	$ 4	$ 0.01
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 101 – 103	$ 0.19	$ 37	$ 0.07
Interest rate change – **1%**	$ 9	$ 0.02	$ 9	$ 0.02

(1) For details of outstanding financial instruments in place, refer to note 11 of the Company's unaudited interim consolidated financial statements.

FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)		**Mar 31 2010**		Dec 31 2009
ASSETS				
Current assets				
Cash and cash equivalents	**$**	**21**	$	13
Accounts receivable		**1,324**		1,148
Inventory, prepaids and other		**640**		584
Future income tax		**–**		146
Current portion of other long-term assets (note 3)		**22**		–
		2,007		1,891
Property, plant and equipment (note 13)		**39,252**		39,115
Other long-term assets (note 3)		**45**		18
	$	**41,304**	$	41,024
LIABILITIES				
Current liabilities				
Accounts payable	**$**	**269**	$	240
Accrued liabilities		**1,914**		1,522
Future income tax		**5**		–
Current portion of other long-term liabilities (note 5)		**353**		643
		2,541		2,405
Long-term debt (note 4)		**8,939**		9,658
Other long-term liabilities (note 5)		**1,878**		1,848
Future income tax		**7,678**		7,687
		21,036		21,598
SHAREHOLDERS' EQUITY				
Share capital (note 7)		**2,939**		2,834
Retained earnings		**17,481**		16,696
Accumulated other comprehensive loss (note 8)		**(152)**		(104)
		20,268		19,426
	$	**41,304**	$	41,024

Commitments (note 12)

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended **Mar 31 2010**	Mar 31 2009
Revenue	**$ 3,580**	$ 2,186
Less: royalties	**(353)**	(199)
Revenue, net of royalties	**3,227**	1,987
Expenses		
Production	**894**	582
Transportation and blending	**414**	317
Depletion, depreciation and amortization	**771**	646
Asset retirement obligation accretion (note 5)	**26**	19
Administration	**54**	47
Stock-based compensation (recovery) expense (note 5)	**(2)**	4
Interest, net	**111**	57
Risk management activities (note 11)	**(169)**	(178)
Foreign exchange (gain) loss	**(160)**	123
	1,939	1,617
Earnings before taxes	**1,288**	370
Taxes other than income tax	**39**	4
Current income tax expense (note 6)	**188**	117
Future income tax expense (recovery) (note 6)	**195**	(56)
Net earnings	**$ 866**	$ 305
Net earnings per common share (note 10)		
Basic and diluted	**$ 1.60**	$ 0.56

Consolidated Statements of Shareholders' Equity

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2010	Mar 31 2009
Share capital (note 7)		
Balance – beginning of period	**$ 2,834**	$ 2,768
Issued upon exercise of stock options	**40**	16
Previously recognized liability on stock options exercised for common shares	**65**	25
Balance – end of period	**2,939**	2,809
Retained earnings		
Balance – beginning of period	**16,696**	15,344
Net earnings	**866**	305
Dividends on common shares (note 7)	**(81)**	(57)
Balance – end of period	**17,481**	15,592
Accumulated other comprehensive (loss) income (note 8)		
Balance – beginning of period	**(104)**	262
Other comprehensive (loss) income, net of taxes	**(48)**	53
Balance – end of period	**(152)**	315
Shareholders' equity	**$ 20,268**	$ 18,716

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2010	Mar 31 2009
Net earnings	**$ 866**	$ 305
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized loss during the period, net of taxes of $1 million (2009 – $2 million)	**(5)**	(17)
Reclassification to net earnings, net of taxes of $nil (2009 – $1 million)	–	(3)
	(5)	(20)
Foreign currency translation adjustment		
Translation of net investment	**(43)**	73
Other comprehensive (loss) income, net of taxes	**(48)**	53
Comprehensive income	**$ 818**	$ 358

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Three Months Ended **Mar 31 2010**	Mar 31 2009
Operating activities		
Net earnings	**$ 866**	$ 305
Non-cash items		
Depletion, depreciation and amortization	**771**	646
Asset retirement obligation accretion	**26**	19
Stock-based compensation (recovery) expense	**(2)**	4
Unrealized risk management (gain) loss	**(208)**	463
Unrealized foreign exchange (gain) loss	**(150)**	138
Deferred petroleum revenue tax expense (recovery)	**7**	(3)
Future income tax expense (recovery)	**195**	(56)
Other	**(26)**	(13)
Abandonment expenditures	**(39)**	(9)
Net change in non-cash working capital	**(79)**	(3)
	1,361	1,491
Financing activities		
Repayment of bank credit facilities, net	**(528)**	(108)
Issue of common shares on exercise of stock options	**40**	16
Dividends on common shares	**(57)**	(54)
Net change in non-cash working capital	**(37)**	(36)
	(582)	(182)
Investing activities		
Net expenditures on property, plant and equipment	**(1,033)**	(1,247)
Net change in non-cash working capital	**262**	(79)
	(771)	(1,326)
Increase (decrease) in cash and cash equivalents	**8**	(17)
Cash and cash equivalents – beginning of period	**13**	27
Cash and cash equivalents – end of period	**$ 21**	$ 10
Interest paid	**$ 152**	$ 184
Taxes (recovered) paid		
Taxes other than income tax	**$ (6)**	$ (25)
Current income tax	**$ 52**	$ 43

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the "Company") include the Company and all of its subsidiaries and partnerships, and have been prepared following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2009. The 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 financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2009.

Comparative Figures

Certain prior period figures have been reclassified to conform to the presentation adopted in 2010.

2. CHANGES IN ACCOUNTING POLICIES

International Financial Reporting Standards

In February 2008, the Canadian Institute of Chartered Accountants' Accounting Standards Board confirmed that Canadian publicly accountable entities will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board in place of generally accepted accounting principles in Canada ("GAAP") effective January 1, 2011. The Company has assessed those accounting policies that will be affected by the change to IFRS and continues to assess the potential impact of these changes on its financial position and results of operations.

Recently issued accounting standards under Canadian GAAP

The following standards will be effective for the Company's year beginning on January 1, 2011:

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

Section 1582 – "Business Combinations", 1601 – "Consolidated Financial Statements", and 1602 – "Non-Controlling Interests" replace Section 1581 – "Business Combinations", and 1600 – "Consolidated Financial Statements". The new standards are the Canadian equivalent of IFRS 3 "Business Combinations" and IAS 27 "Consolidated and Separate Financial Statements". Section 1582 is effective for business combinations for acquisition dates on or after January 1, 2011. Earlier adoption is permitted, provided all three new standards are adopted simultaneously. Section 1582 requires equity instruments issued as part of the purchase consideration to be measured at fair value at the acquisition date, rather than the date when the acquisition was agreed to and announced. In addition, most acquisition costs are expensed as incurred, instead of being included in the purchase consideration. The new standard also requires non-controlling interests to be measured at fair value instead of carrying amounts. Section 1602 provides guidance on the treatment of non-controlling interests after acquisition. Section 1601 carries forward existing guidance on the preparation of consolidated financial statements, other than non-controlling interests. These new standards have no impact on the Company's results of operations or financial position at this time.

3. OTHER LONG–TERM ASSETS

	Mar 31 2010	Dec 31 2009
Risk management (note 11)	**$ 22**	$ –
Other	**45**	18
	67	18
Less: current portion	**22**	–
	$ 45	$ 18

4. LONG–TERM DEBT

	Mar 31 2010	Dec 31 2009
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	**$ 1,369**	$ 1,897
Medium-term notes	**1,200**	1,200
	2,569	3,097
US dollar denominated debt		
US dollar debt securities (2010 and 2009 – US$6,300 million)	**6,398**	6,594
Less: original issue discount on US dollar debt securities (1)	**(21)**	(22)
	6,377	6,572
Fair value of interest rate swaps on US dollar debt securities (2)	**41**	38
	6,418	6,610
Long-term debt before transaction costs	**8,987**	9,707
Less: transaction costs (1) (3)	**(48)**	(49)
	$ 8,939	$ 9,658

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

(2) *The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $41 million (2009 – $38 million) to reflect the fair value impact of hedge accounting.*

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

Bank credit facilities

As at March 31, 2010, the Company had in place unsecured bank credit facilities of $3,953 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are 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 can be made by way of Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

The Company's weighted average interest rate on bank credit facilities outstanding as at March 31, 2010 was 0.8% (December 31, 2009 – 0.8%), and on total long-term debt outstanding as at March 31, 2010 was 4.7% (December 31, 2009 – 4.5%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $371 million, including $300 million related to Horizon, were outstanding at March 31, 2010.

Medium-term notes

The Company filed a $3,000 million base shelf prospectus in October 2009 that allows for the issue of medium-term notes in Canada until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

US dollar debt securities

The Company filed a US$3,000 million base shelf prospectus in October 2009 that allows for the issue of US dollar debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

5. OTHER LONG–TERM LIABILITIES

	Mar 31 2010	Dec 31 2009
Asset retirement obligations	**$ 1,581**	$ 1,610
Stock-based compensation	**291**	392
Risk management (note 11)	**185**	309
Other	**174**	180
	2,231	2,491
Less: current portion	**353**	643
	$ 1,878	$ 1,848

Asset retirement obligations

At March 31, 2010, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $6,546 million (December 31, 2009 – $6,606 million). These costs will be incurred over the lives of the operating assets and have been discounted using a weighted average credit-adjusted risk-free rate of 6.9% (December 31, 2009 – 6.9%). A reconciliation of the discounted asset retirement obligations is as follows:

	Three Months Ended Mar 31, 2010	Year Ended Dec 31, 2009
Balance – beginning of period	**$ 1,610**	$ 1,064
Liabilities incurred [1]	**3**	299
Liabilities settled	**(39)**	(48)
Asset retirement obligation accretion	**26**	90
Revision of estimates	**–**	276
Foreign exchange	**(19)**	(71)
Balance – end of period	**$ 1,581**	$ 1,610

(1) During 2009, the Company recognized additional asset retirement obligations related to Oil Sands Mining and Upgrading and Gabon, Offshore West Africa.

Stock-based compensation

The Company recognizes a liability for the potential cash settlements under its Stock Option Plan. The current portion represents the maximum amount of the liability payable within the next twelve-month period if all vested options are surrendered for cash settlement.

	Three Months Ended Mar 31, 2010	Year Ended Dec 31, 2009
Balance – beginning of period	**$ 392**	$ 171
Stock-based compensation (recovery) expense	**(2)**	355
Cash payments for options surrendered	**(36)**	(94)
Transferred to common shares	**(65)**	(42)
Capitalized to Oil Sands Mining and Upgrading	**2**	2
Balance – end of period	**291**	392
Less: current portion	**258**	365
	$ 33	$ 27

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended	
	Mar 31 2010	Mar 31 2009
Current income tax – North America [1]	**$ 129**	$ 5
Current income tax – North Sea	**53**	98
Current income tax – Offshore West Africa	**6**	14
Current income tax expense	**188**	117
Future income tax expense (recovery)	**195**	(56)
Income tax expense	**$ 383**	$ 61

(1) Includes North America Conventional Crude Oil and Natural Gas, Midstream, and Oil Sands Mining and Upgrading segments.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

The first quarter 2010 future income tax expense includes a charge of $83 million related to the proposed change to the taxation of stock options surrendered by employees for cash. During the first quarter of 2009, substantively enacted or enacted income tax rate changes resulted in a reduction of future income tax liabilities of $19 million in British Columbia.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

7. SHARE CAPITAL

	Three Months Ended Mar 31, 2010	
Issued Common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**542,327**	**$ 2,834**
Issued upon exercise of stock options	**1,435**	**40**
Previously recognized liability on stock options exercised	–	**65**
Balance – end of period	**543,762**	**$ 2,939**

Dividend policy

On March 3, 2010, the Board of Directors set the regular quarterly dividend at $0.15 per common share. The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Normal Course Issuer Bid

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12 month period commencing April 6, 2010 and ending April 5, 2011, up to 13,581,970 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. As at May 6, 2010, no common shares had been purchased for cancellation.

Share split

On March 3, 2010, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 6, 2010.

Stock options

	Three Months Ended Mar 31, 2010	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**32,106**	**$ 58.54**
Granted	**448**	**$ 74.73**
Surrendered for cash settlement	**(993)**	**$ 37.07**
Exercised for common shares	**(1,435)**	**$ 28.12**
Forfeited	**(303)**	**$ 63.91**
Outstanding – end of period	**29,823**	**$ 60.92**
Exercisable – end of period	**10,132**	**$ 57.68**

8. ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

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

	Mar 31 2010	Mar 31 2009
Derivative financial instruments designated as cash flow hedges	**$ 71**	$ 99
Foreign currency translation adjustment	**(223)**	216
	$ (152)	$ 315

9. 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 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 non-GAAP 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 aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the target range when cash flow from operating activities is greater than current investment activities. The ratio is currently at 31%.

Readers are cautioned that the debt to book capitalization ratio is not defined by GAAP 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 2010	Dec 31 2009
Long-term debt	**$ 8,939**	$ 9,658
Total shareholders' equity	**$ 20,268**	$ 19,426
Debt to book capitalization	**31%**	33%

10. NET EARNINGS PER COMMON SHARE

	Three Months Ended	
	Mar 31 2010	Mar 31 2009
Weighted average common shares outstanding (thousands) – basic and diluted	**542,795**	541,251
Net earnings – basic and diluted	**$ 866**	$ 305
Net earnings per common share – basic and diluted	**$ 1.60**	$ 0.56

11. FINANCIAL INSTRUMENTS

The carrying values of the Company's financial instruments by category are as follows:

	Mar 31, 2010		
Asset (liability)	**Loans and receivables at amortized cost**	**Held for trading at fair value**	**Other financial liabilities at amortized cost**
Cash and cash equivalents	**$ –**	**$ 21**	**$ –**
Accounts receivable	**1,324**	**–**	**–**
Other long-term assets	**–**	**22**	**–**
Accounts payable	**–**	**–**	**(269)**
Accrued liabilities	**–**	**–**	**(1,914)**
Other long-term liabilities	**–**	**(185)**	**(163)**
Long-term debt	**–**	**–**	**(8,939)**
	$ 1,324	**$ (142)**	**$ (11,285)**

	Dec 31, 2009		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ –	$ 13	$ –
Accounts receivable	1,148	–	–
Other long-term assets	–	–	–
Accounts payable	–	–	(240)
Accrued liabilities	–	–	(1,522)
Other long-term liabilities	–	(309)	(167)
Long-term debt	–	–	(9,658)
	$ 1,148	$ (296)	$ (11,587)

The carrying value 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 financial assets and liabilities are outlined below:

	Mar 31, 2010		
	Carrying value	**Fair value**	
Asset (liability) [1]		**Level 1**	**Level 2**
Other long-term assets	**$ 22**	**$ –**	**$ 22**
Other long-term liabilities	**(185)**	**–**	**(185)**
Fixed-rate long-term debt[2][3]	**(7,570)**	**(8,034)**	**–**
	$ (7,733)	**$ (8,034)**	**$ (163)**

	Dec 31, 2009		
	Carrying value	Fair value	
Asset (liability) [1]		Level 1	Level 2
Other long-term assets	$ –	$ –	$ –
Other long-term liabilities	(309)	–	(309)
Fixed-rate long-term debt[2][3]	(7,761)	(8,212)	–
	$ (8,070)	$ (8,212)	$ (309)

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

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $41 million (2009 – $38 million) to reflect the fair value impact of hedge accounting.

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

Risk management

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

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

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

	Three Months Ended Mar 31, 2010	Year Ended Dec 31, 2009
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market
Balance – beginning of period	**$ (309)**	$ 2,119
Net change in fair value of outstanding derivative financial instruments attributable to:		
– Risk management activities	**208**	(1,991)
– Interest expense	**3**	(25)
– Foreign exchange	**(59)**	(338)
– Other comprehensive income	**(6)**	(78)
– Settlement of interest rate swaps and other	–	4
Balance – end of period	**(163)**	(309)
Less: current portion	**22**	(182)
	$ (185)	$ (127)

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

	Three Months Ended	
	Mar 31 2010	Mar 31 2009
Net realized risk management loss (gain)	**$ 39**	$ (641)
Net unrealized risk management (gain) loss	**(208)**	463
	$ (169)	$ (178)

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 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. At March 31, 2010, the Company had the following net derivative financial instruments outstanding:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars[(1)]	Apr 2010	–	Jun 2010	100,000 bbl/d	US$60.00	–	US$90.13	WTI
	Apr 2010	–	Sep 2010	50,000 bbl/d	US$65.00	–	US$105.49	WTI
	Apr 2010	–	Dec 2010	50,000 bbl/d	US$60.00	–	US$75.08	WTI
	Jul 2010	–	Dec 2010	50,000 bbl/d	US$65.00	–	US$108.94	WTI

(1) Subsequent to March 31, 2010, the Company entered into 50,000 bbl/d of US$70 –US$105.81 crude oil WTI collars for the period October to December 2010.

	Remaining term			Volume	Weighted average price			Index
Natural gas								
Natural gas price collars	Apr 2010	–	Sep 2010	400,000 GJ/d	C$4.50	–	C$6.30	AECO
	Apr 2010	–	Dec 2010	220,000 GJ/d	C$6.00	–	C$8.00	AECO

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.

There were no commodity derivative financial instruments designated as hedges at March 31, 2010.

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 enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At March 31, 2010, the Company had the following interest rate swap contracts outstanding:

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Apr 2010	–	Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%
Swaps – floating to fixed	Apr 2010	–	Feb 2011	C$300	1.0680%	3 month CDOR (2)
	Apr 2010	–	Feb 2012	C$200	1.4475%	3 month CDOR (2)

(1) London Interbank Offered Rate

(2) Canadian Dealer Offered Rate

All fixed to floating interest rate related derivative financial instruments designated as hedges at March 31, 2010 were classified as fair value hedges.

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 and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its self-sustaining 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 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, 2010, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps(1)	Apr 2010	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Apr 2010	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Apr 2010	–	Mar 2038	US$550	1.170	6.25%	5.76%

(1) Subsequent to March 31, 2010, the Company entered into cross currency swap contracts for US$100 million with an exchange rate of $0.999 (US$/C$) and average interest rates of 6.70% (US$) and 7.64% (C$) for the period April 2010 to July 2011.

All cross currency swap derivative financial instruments designated as hedges at March 31, 2010 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at March 31, 2010, the Company had US$1,184 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at March 31, 2010 resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

		Impact on net earnings		Impact on other comprehensive income
Commodity price risk				
Increase WTI US$1.00/bbl	$	(12)	$	–
Decrease WTI US$1.00/bbl	$	13	$	–
Increase AECO C$0.10/mcf	$	(8)	$	–
Decrease AECO C$0.10/mcf	$	9	$	–
Interest rate risk				
Increase interest rate 1%	$	(8)	$	21
Decrease interest rate 1%	$	6	$	(26)
Foreign currency exchange rate risk				
Increase exchange rate by US$0.01	$	(28)	$	–
Decrease exchange rate by US$0.01	$	28	$	–

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, 2010, 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 non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At March 31, 2010, the Company had net risk management assets of $55 million with specific counterparties related to derivative financial instruments (December 31, 2009 – $7 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, and access to debt capital markets, to meet obligations as they become due. Due to fluctuations in the timing of the receipt and/or disbursement of operating cash flows, the Company believes it has adequate bank credit facilities to provide liquidity.

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 269	$ –	$ –	$ –
Accrued liabilities	$ 1,914	$ –	$ –	$ –
Risk management	$ –	$ 20	$ 66	$ 99
Other long-term liabilities	$ 95	$ 23	$ 26	$ 19
Long-term debt (1)	$ 400	$ 406	$ 1,516	$ 5,276

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,369 million of revolving bank credit facilities due to the extendable nature of the facilities.

12. COMMITMENTS

As at March 31, 2010, the Company had committed to certain payments as follows:

	Remaining 2010	2011	2012	2013	2014	Thereafter
Product transportation and pipeline	$ 160	$ 172	$ 144	$ 134	$ 135	$ 1,060
Offshore equipment operating leases	$ 116	$ 121	$ 100	$ 98	$ 98	$ 254
Offshore drilling	$ 34	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 12	$ 20	$ 21	$ 31	$ 39	$ 6,423
Office leases	$ 19	$ 19	$ 3	$ 2	$ 2	$ 2
Other	$ 211	$ 65	$ 19	$ 14	$ 12	$ 33

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2010 – 2014 represent the estimated minimum expenditures required to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

13. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	Conventional Crude Oil and Natural Gas							
	North America Three Months Ended Mar 31		**North Sea** Three Months Ended Mar 31		**Offshore West Africa** Three Months Ended Mar 31		**Total Conventional** Three Months Ended Mar 31	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009
Segmented revenue	**2,486**	1,847	**286**	175	**156**	201	**2,928**	2,223
Less: royalties	**(324)**	(193)	**(1)**	-	**(5)**	(14)	**(330)**	(207)
Segmented revenue, net of royalties	**2,162**	1,654	**285**	175	**151**	187	**2,598**	2,016
Segmented expenses								
Production	**427**	476	**90**	70	**28**	43	**545**	589
Transportation and blending	**407**	326	**3**	3	**-**	-	**410**	329
Depletion, depreciation and amortization	**557**	547	**83**	64	**39**	50	**679**	661
Asset retirement obligation accretion	**11**	9	**8**	7	**1**	1	**20**	17
Realized risk management activities	**39**	(484)	**-**	(157)	**-**	-	**39**	(641)
Total segmented expenses	**1,441**	874	**184**	(13)	**68**	94	**1,693**	955
Segmented earnings before the following	**721**	780	**101**	188	**83**	93	**905**	1,061
Non-segmented expenses								
Administration								
Stock-based compensation (recovery) expense								
Interest, net								
Unrealized risk management activities								
Foreign exchange (gain) loss								
Total non-segmented expenses								
Earnings before taxes								
Taxes other than income tax								
Current income tax expense								
Future income tax expense (recovery)								
Net earnings								

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading Three Months Ended Mar 31		Midstream Three Months Ended Mar 31		Inter-segment elimination and other Three Months Ended Mar 31		Total Three Months Ended Mar 31	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009
Segmented revenue	**647**	-	**19**	19	**(14)**	(56)	**3,580**	2,186
Less: royalties	**(23)**	-	**-**	-	**-**	8	**(353)**	(199)
Segmented revenue, net of royalties	**624**	-	**19**	19	**(14)**	(48)	**3,227**	1,987
Segmented expenses								
Production	**346**	-	**5**	5	**(2)**	(12)	**894**	582
Transportation and blending	**15**	-	**-**	-	**(11)**	(12)	**414**	317
Depletion, depreciation and amortization	**90**	2	**2**	2	**-**	(19)	**771**	646
Asset retirement obligation accretion	**6**	2	**-**	-	**-**	-	**26**	19
Realized risk management activities	**-**	-	**-**	-	**-**	-	**39**	(641)
Total segmented expenses	**457**	4	**7**	7	**(13)**	(43)	**2,144**	923
Segmented earnings before the following	**167**	(4)	**12**	12	**(1)**	(5)	**1,083**	1,064
Non-segmented expenses								
Administration							**54**	47
Stock-based compensation (recovery) expense							**(2)**	4
Interest, net							**111**	57
Unrealized risk management activities							**(208)**	463
Foreign exchange (gain) loss							**(160)**	123
Total non-segmented expenses							**(205)**	694
Earnings before taxes							**1,288**	370
Taxes other than income tax							**39**	4
Current income tax expense							**188**	117
Future income tax expense (recovery)							**195**	(56)
Net earnings							**866**	305

Net additions to property, plant and equipment

	Three Months Ended					
	Mar 31, 2010			Mar 31, 2009		
	Net Expenditures	**Non Cash/Fair Value Changes (1)**	**Capitalized Costs**	Net Expenditures	Non Cash/Fair Value Changes (1)	Capitalized Costs
North America	**$ 809**	**$ 3**	**$ 812**	$ 599	$ (8)	$ 591
North Sea	**23**	**-**	**23**	42	-	42
Offshore West Africa	**99**	**1**	**100**	215	-	215
Oil Sands Mining and Upgrading (2)	**98**	**-**	**98**	382	270	652
Midstream	**-**	**-**	**-**	5	-	5
Head office	**4**	**-**	**4**	4	-	4
	$ 1,033	**$ 4**	**$ 1,037**	$ 1,247	$ 262	$ 1,509

(1) Asset retirement obligations, future income tax adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for Oil Sands Mining and Upgrading assets also include capitalized interest, stock-based compensation, and the impact of inter-segment eliminations.

	Property, plant and equipment		Total assets	
	Mar 31 2010	Dec 31 2009	**Mar 31 2010**	Dec 31 2009
Segmented assets				
North America	**$ 22,097**	$ 21,834	**$ 23,253**	$ 22,994
North Sea	**1,699**	1,812	**1,829**	1,968
Offshore West Africa	**1,863**	1,883	**2,018**	2,033
Other	**29**	28	**64**	42
Oil Sands Mining and Upgrading	**13,303**	13,295	**13,753**	13,621
Midstream	**201**	203	**327**	306
Head office	**60**	60	**60**	60
	$ 39,252	$ 39,115	**$ 41,304**	$ 41,024

Capitalized interest

The Company capitalizes construction period interest to Oil Sands Mining and Upgrading activities based on costs incurred and the Company's cost of borrowing. Interest capitalization on a particular development phase ceases once construction is substantially complete. For the three months ended March 31, 2010, pre-tax interest of $7 million was capitalized to Oil Sands Mining and Upgrading (March 31, 2009 – $86 million).

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated October 2009. 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, 2010:	
Interest coverage (times)	
Net earnings [(1)]	6.6 x
Cash flow from operations [(2)]	14.3 x

(1) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

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

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Friday, May 7, 2010. The North American conference call number is 1-800-769-8320 and the outside North American conference call number is 001-416-695-6616. Please call in about 10 minutes before the starting time in order to be patched into the call. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Friday, May 14, 2010. To access the postview in North America, dial 1-800-408-3053. Those outside of North America, dial 001-416-695-5800. The passcode to use is 6353533.

WEBCAST

This call is being webcast and can be accessed on Canadian Natural's website at www.cnrl.com.

2010 SECOND QUARTER RESULTS

The 2010 second quarter results are scheduled for release on Thursday, August 5, 2010. A conference call is scheduled to be held the same day. Details can be found on our website www.cnrl.com.

For further information, please contact:

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