PRESS RELEASE

Canadian Natural

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2009 SECOND QUARTER RESULTS

CALGARY, ALBERTA – AUGUST 6, 2009 – FOR IMMEDIATE RELEASE

Canadian Natural's Chairman, Allan Markin, stated, "The ramp-up of production at Horizon continued to go well during the second quarter with production of SCO exceeding our corporate guidance. While we have made significant progress and remain optimistic about ramp-up, we are cognizant of the challenges associated with getting a facility of this size and complexity operating consistently and reliably at design capacity. Horizon and Offshore West Africa contributed to an 11% crude oil production growth quarter over quarter."

John Langille, Vice-Chairman of Canadian Natural continued, "For the first half of the year we benefited from favorable heavy oil differentials and our hedging program contributed to strong cash flow. During the quarter, the commencement of SCO sales from Horizon added to cash flow which helped offset the impact of weak natural gas prices and the expected declines in natural gas production. We continue to focus on internally generated cash flow, our flexible capital allocation and balance sheet strength."

Steve Laut, President and Chief Operating Officer of Canadian Natural concluded, "The strength and value of Canadian Natural's strategy, our balanced asset base and ability to quickly respond to changing market conditions has never been more clear. Our current focus remains on crude oil as returns continue to be more attractive than natural gas. We have increased drilling on heavy crude oil which benefited from narrow pricing differentials relative to WTI during the second quarter. We are also concentrating on ramping up production at Horizon which is providing high-quality, high-value crude oil. For natural gas we will continue to position the Company by maintaining our extensive land base, building an even stronger inventory of prospects and focusing on cost reduction and control until economics significantly improve for natural gas projects."

HIGHLIGHTS

	Three Months Ended			Six Months Ended	
($ millions, except as noted)	**Jun 30 2009**	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Net earnings (loss)	**$ 162**	$ 305	$ (347)	**$ 467**	$ 380
per common share, basic and diluted	**$ 0.30**	$ 0.56	$ (0.65)	**$ 0.86**	$ 0.70
Adjusted net earnings from operations (1)	**$ 637**	$ 727	$ 960	**$ 1,364**	$ 1,832
per common share, basic and diluted	**$ 1.18**	$ 1.34	$ 1.78	**$ 2.52**	$ 3.39
Cash flow from operations (2)	**$ 1,365**	$ 1,516	$ 1,859	**$ 2,881**	$ 3,584
per common share, basic and diluted	**$ 2.52**	$ 2.80	$ 3.44	**$ 5.32**	$ 6.63
Capital expenditures, net of dispositions	**$ 473**	$ 1,256	$ 2,127	**$ 1,729**	$ 3,880
Daily production, before royalties					
Natural gas (mmcf/d)	**1,352**	1,369	1,526	**1,360**	1,532
Crude oil and NGLs (bbl/d)	**365,672**	330,017	319,077	**347,943**	323,147
Equivalent production (boe/d)	**590,984**	558,142	573,437	**574,654**	578,461

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and debt repayment. The derivation of this measure is discussed in the MD&A.

HIGHLIGHTS

- Total crude oil and NGLs production for Q2/09 was 365,672 bbl/d, an increase of 11% from the previous quarter. Volumes in Q2/09 reflect production from Horizon and Baobab, the commencement of production from Olowi, and continued conversion of production wells to polymer injection wells at Pelican Lake. Increased volumes were offset by the transition between steam and production cycles for Primrose thermal wells and a temporary curtailment at Primrose East.
- Natural gas production for Q2/09 averaged 1,352 mmcf/d, down 1% from the previous quarter, as expected. The decrease in volumes for Q2/09 from previous quarters reflects the continuing reallocation of capital towards higher return crude oil projects.
- Quarterly cash flow from operations was $1,365 million, a decrease of 10% from the previous quarter. The decrease from Q1/09 reflects lower natural gas price realizations and lower natural gas sales volumes, partially offset by the impact of higher crude oil price realizations and higher crude oil sales volumes.
- Quarterly net earnings for Q2/09 of $162 million included the effects of unrealized risk management activities, stock-based compensation and fluctuations in foreign exchange rates. Excluding these items, quarterly adjusted net earnings from operations for Q2/09 were $637 million, a decrease of 12% from the previous quarter.
- The drilling program at Baobab in Offshore Côte d'Ivoire was completed and the fourth well was brought on production in early Q2/09. The four re-drilled wells restored production of approximately 11,000 bbl/d net to Canadian Natural.
- First crude oil production was achieved at the Olowi Field in Offshore Gabon on April 28, 2009. Initial production volumes from Platform C are below the Company's expectations. Platforms A, B and D will be drilled and completed during the next 18 months.
- Horizon production averaged 59,599 bbl/d of SCO ("Synthetic Crude Oil") for Q2/09, with production ramp-up exceeding expectations in May and June. The overall production schedule remains unchanged, with reliable and consistent production at design capacity targeted for Q4/09.
- Declared a quarterly cash dividend on common shares of $0.105 per common share payable October 1, 2009.

OPERATIONS REVIEW

Activity by core region

	Net undeveloped land as at Jun 30, 2009 (thousands of net acres)	**Drilling activity six months ended Jun 30, 2009 (net wells) (1)**
North America conventional		
Northeast British Columbia	**2,147**	**15.0**
Northwest Alberta	**1,222**	**33.2**
Northern Plains	**5,944**	**164.1**
Southern Plains	**833**	**8.3**
Southeast Saskatchewan	**134**	**3.0**
Thermal In-situ Oil Sands	**489**	**242.0**
	10,769	**465.6**
Oil Sands Mining and Upgrading	**115**	**42.0**
North Sea	**183**	**0.9**
Offshore West Africa	**188**	**4.2**
	11,255	**512.7**

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

Drilling activity (number of wells)

	Six Months Ended Jun 30			
	2009		2008	
	Gross	**Net**	Gross	Net
Crude oil	**192**	**187**	284	266
Natural gas	**87**	**64**	202	166
Dry	**20**	**19**	20	17
Subtotal	**299**	**270**	506	449
Stratigraphic test / service wells	**243**	**243**	26	26
Total	**542**	**513**	532	475
Success rate (excluding stratigraphic test / service wells)		**93%**		96%

North America Conventional

North America natural gas

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Natural gas production (mmcf/d)	**1,322**	1,347	1,501	**1,334**	1,507
Net wells targeting natural gas	**-**	72	8	**72**	175
Net successful wells drilled	**-**	64	5	**64**	166
Success rate	**-**	89%	63%	**89%**	95%

- Q2/09 North America natural gas production decreased 12% as expected from Q2/08, and decreased 2% from Q1/09, reflecting natural declines in base production and the Company's strategic decision to reduce spending on natural gas drilling due to stronger economics in crude oil projects.
- Canadian Natural chose to not drill any net natural gas wells in Q2/09, however completed all planned tie-ins from wells drilled during Q1/09.
- Planned drilling activity for Q3/09 includes 24 net natural gas wells. Based on near term economics, the Company continues to focus on land expiries, competitive drainage issues and advancing development of key resource projects.

North America crude oil and NGLs

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Crude oil and NGLs production (bbl/d)	**232,139**	253,833	245,616	**242,926**	247,288
Net wells targeting crude oil	**97**	97	94	**194**	270
Net successful wells drilled	**93**	90	92	**183**	263
Success rate	**96%**	93%	98%	**94%**	97%

- Q2/09 North America crude oil and NGLs production decreased 5% from Q2/08 and decreased 9% from Q1/09 levels. The majority of the decline in production volumes was in thermal crude oil as Primrose North and South transitioned to a steam cycle and a temporary curtailment of thermal steam/production cycle at Primrose East is in effect.
- As stated previously, in Q1/09 after initial steaming, Canadian Natural discovered oil seepage at the surface on one of the new multi-well pads at Primrose East. A significant amount of diagnostic work has been completed and the Company believes it has identified the issue and the remedial action required. The Company continues to proactively work with the regulators on resolving the issue and returning Primrose East to normal operations. Canadian Natural has received regulatory approval for diagnostic steaming which is targeted to commence August 2009.
- Canadian Natural is continuing its proposed third phase of the thermal growth plan with a development plan for the 45,000 bbl/d Kirby In-Situ Oil Sands Project located approximately 85 km northeast of Lac La Biche in the Regional Municipality of Wood Buffalo. The Company has filed its formal regulatory application documents for this project and is awaiting regulatory approval. Canadian Natural expects to decide in early 2010 on the timing of the development of the project.
- Development of new pads and conversion to tertiary recovery at Pelican Lake continued as expected throughout Q2/09. In Q2/09, the Company drilled 19 horizontal wells and plans to drill one vertical service well and an additional 34 horizontal wells throughout the remainder of 2009. Pelican Lake production averaged approximately 36,000 bbl/d for Q2/09.
- Conventional heavy crude oil production volumes increased slightly in Q2/09 compared to Q1/09, reflecting increased drilling in Q2/09. The Company increased drilling of heavy crude oil wells to take advantage of the pricing and narrow heavy crude oil differentials.
- During Q2/09, drilling activity targeted 97 net wells including 48 wells targeting heavy crude oil, 19 wells targeting Pelican Lake crude oil and 30 wells targeting thermal crude oil.
- Planned drilling activity for Q3/09 includes 238 net crude oil wells, excluding stratigraphic test and service wells.

International

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Crude oil production (bbl/d)					
North Sea	**40,362**	42,369	45,830	**41,360**	47,699
Offshore West Africa	**33,572**	30,431	27,631	**32,010**	28,160
Natural gas production (mmcf/d)					
North Sea	**10**	10	10	**10**	11
Offshore West Africa	**20**	12	15	**16**	14
Net wells targeting crude oil	**1.0**	3.2	1.6	**4.2**	3.8
Net successful wells drilled	**1.0**	3.2	0.8	**4.2**	3.0
Success rate	**100%**	100%	50%	**100%**	79%

North Sea

- Production, as expected, was lower than Q1/09 due to planned maintenance shutdowns at the Ninian Field, however still exceeded the top end of the Company's production guidance range. During the quarter, focus continued on lowering costs and high grading inventory and infill drilling opportunities.
- The Deep Banff exploration well did not find commercial hydrocarbons and was plugged and abandoned early in the third quarter. Canadian Natural's net paying interest in the well was approximately 19%.

Offshore West Africa

- Offshore West Africa's crude oil production for Q2/09 was 33,572 bbl/d, an increase of 10% from Q1/09. This was largely due to the fourth and final well in the Baobab drilling program coming on line and first crude oil production from the Olowi Field.
- Progress on the Facility Upgrade Project at Espoir to increase processing capacity of the Floating Production Storage and Offtake Vessel ("FPSO") has reverted to the original schedule to accommodate effective utilization of the installation vessel at Olowi.
- At the Olowi Project in Offshore Gabon, one further production well and one gas injector well were completed. The FPSO and Conductor Supported Platform were commissioned and first production of crude oil was achieved April 28, 2009. Further drilling and development activity of Olowi will continue through 2010. Initial production volumes from Platform C are below the Company's expectations. Platforms A, B and D will be drilled and completed during the next 18 months.

Oil Sands Mining and Upgrading

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Synthetic Crude Oil Production (bbl/d)	**59,599**	3,384	-	**31,647**	-

- Horizon production in Q2/09 averaged 59,599 bbl/d of SCO, above the guidance range previously provided.
- During the quarter, the Company experienced better than expected production. The Horizon operation has tested production over the design capacity of 110,000 bbl/d of SCO on several occasions helping determine debottleneck opportunities. All major components of the plant have been tested and to date have shown no significant long term issues with design or capacity limitations.
- During the initial stages of ramp-up, as expected, production volumes continue to fluctuate. The plant continues to be fine tuned with a focus on safety, reliability, and cost control with targeted stability approaching design capacity in Q4/09.
- Engineering and procurement is underway for Tranche 2 of the Phase 2/3 expansion 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			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Crude oil and NGLs pricing					
WTI [1] benchmark price (US$/bbl)	**$ 59.61**	$ 43.21	$ 124.00	**$ 51.46**	$ 110.98
Western Canadian Select blend differential from WTI (%)	**13%**	21%	17%	**16%**	19%
SCO (discount) premium from WTI (US$/bbl)	**$ (1.19)**	$ 1.76	$ 4.78	**$ 0.28**	$ 3.80
Corporate average pricing before risk management (C$/bbl)	**$ 59.56**	$ 41.25	$ 103.73	**$ 50.12**	$ 91.11
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 3.46**	$ 5.34	$ 8.86	**$ 4.40**	$ 7.81
Corporate average pricing before risk management (C$/mcf)	**$ 4.11**	$ 5.46	$ 9.89	**$ 4.78**	$ 8.83

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

- In Q2/09, the Western Canadian Select ("WCS") heavy crude oil differential as a percent of WTI was 13% compared to 21% in Q1/09. Heavy crude oil differentials continued to narrow in Q2/09 due to stronger demand from the US refineries for heavy crude oil. The US refineries are experiencing weak refinery margins and this tends to increase the demand for the lowest cost crude oil, which is generally heavier crude oil.
- During Q2/09, the Company allocated approximately 138,000 bbl/d of its heavy crude oil streams to the WCS blend, optimizing the pricing for heavy crude oil.
- The marketing strategy for Horizon SCO remains flexible. There is an active market for the product and Horizon SCO has been favorably accepted by refiners.
- Natural gas pricing for Q2/09 weakened compared to prior periods primarily due to supply/demand imbalances. North America natural gas inventory levels remained high during the second quarter due to lower industrial consumption and an oversupply from US producers.

FINANCIAL REVIEW

- The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its commodity hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing 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. A brief summary of the Company's strengths are:
  - A diverse asset base geographically and by product - produced in excess of 590,000 boe/d in Q2/09, comprised of approximately 38% natural gas and 62% crude oil - with approximately 94% of production located in G8 countries.
  - Financial stability and liquidity - cash flow from operations of $1,365 million for Q2/09, with available unused bank lines of $1,749 million at June 30, 2009.
  - Reduced volatility of commodity prices - a proactive commodity hedging program to reduce the downside risk of volatility in commodity prices supporting cash flow for its capital expenditure program.
  - In Q2/09 the Company repaid $560 million on the non-revolving syndicated acquisition credit facility maturing in October 2009. An additional $350 million has been repaid to date in Q3/09.
  - A strengthening balance sheet with debt to book capitalization of 39% and debt to EBITDA of 1.8 times, both within targeted ranges.
- Declared a quarterly cash dividend on common shares of C$0.105 per common share, payable October 1, 2009.

OUTLOOK

- The Company forecasts 2009 production levels before royalties to average between 1,289 and 1,330 mmcf/d of natural gas and between 346,000 and 382,000 bbl/d of crude oil and NGLs. Q3/09 production guidance before royalties is forecast to average between 1,274 and 1,304 mmcf/d of natural gas and between 363,000 and 389,000 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 http://www.cnrl.com/investor_info/corporate_guidance/.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule" 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, Gabon Offshore West Africa, and the Kirby 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 and 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 liquids 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 six months ended June 30, 2009 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2008.

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 six and three months ended June 30, 2009 in relation to the comparable periods in 2008 and the first quarter of 2009. The accompanying tables form an integral part of this MD&A. This MD&A is dated August 4, 2009. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2008, is available on SEDAR at www.sedar.com.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Revenue, before royalties	**$ 2,750**	$ 2,186	$ 5,112	**$ 4,936**	$ 9,079
Net earnings (loss)	**$ 162**	$ 305	$ (347)	**$ 467**	$ 380
Per common share – basic and diluted	**$ 0.30**	$ 0.56	$ (0.65)	**$ 0.86**	$ 0.70
Adjusted net earnings from operations (1)	**$ 637**	$ 727	$ 960	**$ 1,364**	$ 1,832
Per common share – basic and diluted	**$ 1.18**	$ 1.34	$ 1.78	**$ 2.52**	$ 3.39
Cash flow from operations (2)	**$ 1,365**	$ 1,516	$ 1,859	**$ 2,881**	$ 3,584
Per common share – basic and diluted	**$ 2.52**	$ 2.80	$ 3.44	**$ 5.32**	$ 6.63
Capital expenditures, net of dispositions	**$ 473**	$ 1,256	$ 2,127	**$ 1,729**	$ 3,880

(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

($ millions)	*Three Months Ended*			*Six Months Ended*	
	Jun 30 2009	*Mar 31 2009*	*Jun 30 2008*	***Jun 30 2009***	*Jun 30 2008*
Net earnings (loss) as reported	***$ 162***	*$ 305*	*$ (347)*	***$ 467***	*$ 380*
Stock-based compensation expense, net of tax (a)	***67***	*3*	*328*	***70***	*328*
Unrealized risk management loss, net of tax (b)	***676***	*320*	*997*	***996***	*1,073*
Unrealized foreign exchange (gain) loss, net of tax (c)	***(268)***	*118*	*(18)*	***(150)***	*92*
Effect of statutory tax rate and other legislative changes on future income tax liabilities (d)	***-***	*(19)*	*–*	***(19)***	*(41)*
Adjusted net earnings from operations	***$ 637***	*$ 727*	*$ 960*	***$ 1,364***	*$ 1,832*

(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. 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. Income tax rate changes in the first quarter of 2008 resulted in a reduction of future income tax liabilities of approximately $19 million in North America and $22 million in Côte d'Ivoire, Offshore West Africa.

Cash Flow from Operations

($ millions)	Three Months Ended **Jun 30 2009**	Mar 31 2009	Jun 30 2008	Six Months Ended **Jun 30 2009**	Jun 30 2008
Net earnings (loss)	**$ 162**	$ 305	$ (347)	**$ 467**	$ 380
Non-cash items:					
Depletion, depreciation and amortization	**664**	646	670	**1,310**	1,358
Asset retirement obligation accretion	**24**	19	17	**43**	34
Stock-based compensation expense	**92**	4	459	**96**	459
Unrealized risk management loss	**946**	463	1,415	**1,409**	1,523
Unrealized foreign exchange (gain) loss	**(320)**	138	(20)	**(182)**	106
Deferred petroleum revenue tax recovery	**(2)**	(3)	(34)	**(5)**	(55)
Future income tax recovery	**(201)**	(56)	(301)	**(257)**	(221)
Cash flow from operations	**$ 1,365**	$ 1,516	$ 1,859	**$ 2,881**	$ 3,584

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the six months ended June 30, 2009 were $467 million compared to $380 million for the six months ended June 30, 2008. Net earnings for the six months ended June 30, 2009 included net unrealized after-tax expenses of $897 million related to the effects of risk management activities, fluctuations in foreign exchange rates, fluctuations in stock-based compensation expense, and the impact of statutory tax rate changes on future income tax liabilities, compared to net unrealized after-tax expenses of $1,452 million for the six months ended June 30, 2008. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2009 were $1,364 million compared to $1,832 million for the six months ended June 30, 2008. The decrease in adjusted net earnings from the six months ended June 30, 2008 was primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expenses, higher interest expense, and higher realized foreign exchange losses, partially offset by the impact of higher crude oil sales volumes related to the commencement of operations of Horizon Oil Sands ("Horizon"), higher realized risk management gains, lower depletion, depreciation and amortization expense, lower royalty expense, and the impact of the weaker Canadian dollar relative to the US dollar.

Net earnings for the second quarter of 2009 were $162 million compared to a net loss of $347 million for the second quarter of 2008 and net earnings of $305 million for the prior quarter. Net earnings for the second quarter of 2009 included net unrealized after-tax expenses of $475 million related to the effects of risk management activities, fluctuations in foreign exchange rates, and fluctuations in stock-based compensation expense, compared to net unrealized after-tax expenses of $1,307 million for the second quarter of 2008 and net unrealized after-tax expenses of $422 million for the prior quarter. Excluding these items, adjusted net earnings from operations for the second quarter of 2009 were $637 million compared to $960 million for the second quarter of 2008 and $727 million for the prior quarter. The decrease in adjusted net earnings from the second quarter of 2008 was primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expense, and higher interest expense, partially offset by the impact of higher realized risk management gains, lower royalty expense, and the impact of the weaker Canadian dollar relative to the US dollar. The decrease in adjusted net earnings from the prior quarter was primarily due to the impact of lower natural gas sales volumes and realized pricing, lower realized risk management gains, higher depletion, depreciation and amortization expense, higher royalty and production expense, higher interest expense, and the impact of the stronger Canadian dollar relative to the US dollar, partially offset by the impact of higher crude oil sales volumes related to the commencement of operations of 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 six months ended June 30, 2009 was $2,881 million compared to $3,584 million for the six months ended June 30, 2008. Cash flow from operations for the second quarter of 2009 was $1,365 million compared to $1,859 million for the second quarter of 2008 and $1,516 million for the prior quarter. The decrease in cash flow from operations from the comparable periods in 2008 was primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expense, higher interest expense, and higher realized foreign exchange losses, partially offset by the impact of higher crude oil sales volumes related to the commencement of operations of Horizon, higher realized risk management gains, lower royalty expense, lower current income tax and current Production Revenue Tax ("PRT") expense, and the impact of the weaker Canadian dollar relative to the US dollar. The decrease in cash flow from operations from the prior quarter was primarily due to the impact of lower natural gas sales volumes, lower realized natural gas pricing, lower realized risk management gains, higher royalty and production expense, higher interest expense, higher realized foreign exchange losses, higher current PRT, and the impact of the stronger Canadian dollar relative to the US dollar, partially offset by the impact of higher crude oil sales volumes related to the commencement of operations of Horizon, higher realized crude oil pricing, and lower current income tax expense.

During 2009, the Company achieved first production of synthetic crude oil ("SCO") at Horizon in connection with the commencement of operations. The Company continues to focus on stabilizing and ramping up production as the plant is fine tuned with a focus on safety, reliability, and cost control. The results of operations for Horizon are included in the Oil Sands Mining and Upgrading segment.

Total production before royalties for the six months ended June 30, 2009 decreased 1% to 574,654 boe/d from 578,461 boe/d for the six months ended June 30, 2008. Total production before royalties for the second quarter of 2009 increased 3% to 590,984 boe/d from 573,437 boe/d for the second quarter of 2008 and increased 6% from 558,142 boe/d for the prior quarter. Total production for the second quarter of 2009 was above the Company's previously issued guidance.

For a discussion of the impact of current worldwide financial and economic events, please refer to the "Liquidity and Capital Resources" section of this MD&A.

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)	**Jun 30 2009**	Mar 31 2009	Dec 31 2008	Sep 30 2008
Revenue, before royalties	**$ 2,750**	$ 2,186	$ 2,511	$ 4,583
Net earnings	**$ 162**	$ 305	$ 1,770	$ 2,835
Net earnings per common share				
– Basic and diluted	**$ 0.30**	$ 0.56	$ 3.27	$ 5.25

($ millions, except per common share amounts)	Jun 30 2008	Mar 31 2008	Dec 31 2007	Sep 30 2007
Revenue, before royalties	$ 5,112	$ 3,967	$ 3,200	$ 3,073
Net earnings (loss)	$ (347)	$ 727	$ 798	$ 700
Net earnings (loss) per common share				
– Basic and diluted	$ (0.65)	$ 1.35	$ 1.48	$ 1.30

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** – Increased production from the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the commencement of operations of Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore West Africa and the impact of the shut in, and subsequent restoration, of some of the Baobab Field production.

- **Natural gas sales volumes** – Production declines due to the Company's strategic decision to reduce natural gas drilling activity in North America due to the allocation of capital to higher return crude oil projects, as well as natural decline rates.
- **Production expense** – Fluctuations company wide, primarily due to the impact of the demand for services, industry-wide inflationary cost pressures experienced in prior quarters in all segments, fluctuations in product mix, and the impact of seasonal costs that are dependent on weather.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, finding and development costs associated with crude oil and natural gas exploration, and estimated future costs to develop the Company's proved undeveloped reserves.
- **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 over the eight most recently completed quarters.
- **Risk management** – Fluctuations due to the recognition of realized and unrealized 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. Similarly, unrealized foreign exchange gains and losses were 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.
- **Changes in 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

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
WTI benchmark price (US$/bbl)	**$ 59.61**	$ 43.21	$ 124.00	**$ 51.46**	$ 110.98
Dated Brent benchmark price (US$/bbl)	**$ 58.78**	$ 44.45	$ 121.39	**$ 51.65**	$ 109.17
WCS blend differential from WTI (US$/bbl)	**$ 7.43**	$ 8.98	$ 21.62	**$ 8.20**	$ 21.51
WCS blend differential from WTI (%)	**13%**	21%	17%	**16%**	19%
SCO (discount) premium from WTI (US$/bbl)	**$ (1.19)**	$ 1.76	$ 4.78	**$ 0.28**	$ 3.80
Condensate benchmark price (US$/bbl)	**$ 58.30**	$ 43.44	$ 124.64	**$ 50.91**	$ 111.52
NYMEX benchmark price (US$/mmbtu)	**$ 3.59**	$ 4.87	$ 10.80	**$ 4.23**	$ 9.44
AECO benchmark price (C$/GJ)	**$ 3.46**	$ 5.34	$ 8.86	**$ 4.40**	$ 7.81
US / Canadian dollar average exchange rate	**$ 0.8571**	$ 0.8028	$ 0.9900	**$ 0.8293**	$ 0.9929

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$51.46 per bbl for the six months ended June 30, 2009, a decrease of 54% from US$110.98 per bbl for the six months ended June 30, 2008. WTI averaged US$59.61 per bbl for the second quarter of 2009, a decrease of 52% from US$124.00 per bbl for the second quarter of 2008, and an increase of 38% from US$43.21 per bbl for the prior quarter. Despite the increase in WTI pricing from the prior quarter, WTI pricing during the second quarter of 2009 continued to be impacted by a significant decrease in demand as a result of worldwide financial and economic events and ongoing geopolitical uncertainty resulting in increased market volatility.

Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Dated Brent ("Brent") pricing, which also continued to be impacted by worldwide financial and economic events during the second quarter of 2009. Brent averaged US$51.65 per bbl for the six months ended June 30, 2009, a decrease of 53% compared to US$109.17 per bbl for the six months ended June 30, 2008. Brent averaged US$58.78 per bbl for the second quarter of 2009, a decrease of 52% compared to US$121.39 per bbl for the second quarter of 2008, and an increase of 32% from US$44.45 per bbl for the prior quarter.

The Heavy Differential averaged 16% for the six months ended June 30, 2009 compared to 19% for the six months ended June 30, 2008. The Heavy Differential averaged 13% for the second quarter of 2009 compared to 17% for the second quarter of 2008, and 21% for the prior quarter. The narrowing of the Heavy Differential from the prior periods was primarily due to relatively weak refinery margins and lower supply available from Venezuela and Mexico. The Heavy differential was narrower in the second quarter as economic events resulted in lower demand for finished products and a market oversupplied with crude oil. Generally, reduced refinery margins lead to lower refinery utilization and narrower heavy oil differentials.

During the second quarter of 2009, the Company began marketing SCO production from Horizon. SCO is generally priced using the WTI benchmark.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events and the global economic slowdown resulting from worldwide financial and economic events. The Heavy Differential is expected to reflect seasonal demand fluctuations and refinery margins.

NYMEX natural gas prices averaged US$4.23 per mmbtu for the six months ended June 30, 2009, a decrease of 55% from US$9.44 per mmbtu for the six months ended June 30, 2008. NYMEX natural gas prices averaged US$3.59 per mmbtu for the second quarter of 2009, a decrease of 67% from US$10.80 per mmbtu for the second quarter of 2008, and a decrease of 26% from US$4.87 per mmbtu for the prior quarter. AECO natural gas prices for the six months ended June 30, 2009 decreased 44% to average $4.40 per GJ from $7.81 per GJ for the six months ended June 30, 2008. AECO natural gas prices for the second quarter of 2009 decreased 61% to average $3.46 per GJ from $8.86 per GJ in the second quarter of 2008, and decreased 35% from $5.34 per GJ for the prior quarter. Decreases in natural gas prices from the comparable periods were primarily related to an oversupply in the market. Natural gas production continued to exceed expectations primarily as a result of new shale gas production in the United States.

Update to Alberta Royalty Framework

Effective January 1, 2009, changes to the Alberta royalty regime under the Alberta Royalty Framework (“ARF”) include 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, effective January 1, 2009, new royalty formulas under the ARF for conventional crude oil and natural gas are to operate on sliding scales ranging up to 50%, determined by commodity prices and well productivity.

In March 2009, the Government of Alberta announced new incentive programs to stimulate activity in Alberta. These programs provide for:

- A royalty credit of $200 per meter on new conventional crude oil and natural gas wells drilled between April 1, 2009 and March 31, 2010.
- Reduced royalty rates that set the maximum royalty at 5% for the first 12 months of production, up to a maximum of 50,000 bbl or 500 mmcf, for new conventional crude oil and natural gas wells that commence production between April 1, 2009 and March 31, 2010.

In June 2009, the Government of Alberta extended the two incentive programs described above by one year, to March 31, 2011.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Crude oil and NGLs (bbl/d)					
North America – Conventional	**232,139**	253,833	245,616	**242,926**	247,288
North America – Oil Sands Mining and Upgrading	**59,599**	3,384	–	**31,647**	–
North Sea	**40,362**	42,369	45,830	**41,360**	47,699
Offshore West Africa	**33,572**	30,431	27,631	**32,010**	28,160
	365,672	330,017	319,077	**347,943**	323,147
Natural gas (mmcf/d)					
North America	**1,322**	1,347	1,501	**1,334**	1,507
North Sea	**10**	10	10	**10**	11
Offshore West Africa	**20**	12	15	**16**	14
	1,352	1,369	1,526	**1,360**	1,532
Total barrels of oil equivalent (boe/d)	**590,984**	558,142	573,437	**574,654**	578,461
Product mix					
Light/medium crude oil and NGLs	**21%**	22%	22%	**21%**	22%
Pelican Lake crude oil	**6%**	6%	6%	**6%**	6%
Primary heavy crude oil	**14%**	15%	16%	**15%**	16%
Thermal heavy crude oil	**11%**	15%	12%	**13%**	12%
Synthetic crude oil	**10%**	1%	–	**6%**	–
Natural gas	**38%**	41%	44%	**39%**	44%
Percentage of gross revenue (1) (excluding midstream revenue)					
Crude oil and NGLs	**79%**	64%	68%	**71%**	68%
Natural gas	**21%**	36%	32%	**29%**	32%

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Crude oil and NGLs (bbl/d)					
North America – Conventional	**197,281**	224,506	202,264	**210,819**	209,424
North America – Oil Sands Mining and Upgrading	**58,467**	3,362	–	**31,067**	–
North Sea	**40,292**	42,265	45,734	**41,273**	47,603
Offshore West Africa	**30,470**	28,341	24,136	**29,411**	23,816
	326,510	298,474	272,134	**312,570**	280,843
Natural gas (mmcf/d)					
North America	**1,313**	1,180	1,227	**1,247**	1,243
North Sea	**10**	10	10	**10**	11
Offshore West Africa	**18**	11	13	**15**	12
	1,341	1,201	1,250	**1,272**	1,266
Total barrels of oil equivalent (boe/d)	**550,053**	498,740	480,418	**524,538**	491,835

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 six months ended June 30, 2009 increased 8% to 347,943 bbl/d from 323,147 bbl/d for the six months ended June 30, 2008. The increase from the comparable period was primarily due to the commencement of production from Horizon and the Olowi Field in Offshore Gabon.

Total crude oil and NGLs production for the second quarter of 2009 increased 15% to 365,672 bbl/d from 319,077 bbl/d for the second quarter of 2008, and increased 11% from 330,017 bbl/d for the prior quarter. The increase from the second quarter in 2008 and the prior quarter was primarily due to production from Horizon and the commencement of production from the Olowi Field in Offshore Gabon. Crude oil and NGLs production in the second quarter of 2009 was above the Company's previously issued guidance of 321,000 to 359,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering for the six months ended June 30, 2009, accounting for 39% of the Company's total production. Natural gas production for the six months ended June 30, 2009 averaged 1,360 mmcf/d compared to 1,532 mmcf/d for the six months ended June 30, 2008. Natural gas production for the second quarter of 2009 averaged 1,352 mmcf/d compared to 1,526 mmcf/d for the second quarter of 2008 and 1,369 mmcf/d for the prior quarter. The decrease in natural gas production from the comparable periods primarily reflected production declines due to the Company's strategic reduction in natural gas drilling activity. Natural gas production in the second quarter of 2009 was on the high end of the Company's previously issued guidance of 1,318 to 1,353 mmcf/d.

For 2009, revised annual production guidance is targeted to average between 346,000 and 382,000 bbl/d of crude oil and NGLs and between 1,289 and 1,330 mmcf/d of natural gas. Third quarter 2009 production guidance is targeted to average between 363,000 and 389,000 bbl/d of crude oil and NGLs and between 1,274 and 1,304 mmcf/d of natural gas.

North America – Conventional

North America conventional crude oil and NGLs production for the six months ended June 30, 2009 decreased 2% to average 242,926 bbl/d from 247,288 bbl/d for the six months ended June 30, 2008. Second quarter North America conventional crude oil and NGLs production decreased 5% to average 232,139 bbl/d from 245,616 bbl/d for the second quarter of 2008, and decreased 9% from 253,833 bbl/d for the prior quarter. The decrease in crude oil and NGLs production from the prior periods 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 217,000 bbl/d to 227,000 bbl/d for the second quarter of 2009.

Natural gas production for the six months ended June 30, 2009 decreased 11% to 1,334 mmcf/d from 1,507 mmcf/d for the six months ended June 30, 2008. For the second quarter of 2009, natural gas production decreased 12% to 1,322 mmcf/d from 1,501 mmcf/d for the second quarter of 2008, and decreased 2% from 1,347 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.

North America – Oil Sands Mining and Upgrading

Horizon Phase 1 achieved first production of synthetic crude oil during 2009. Production for the six months ended June 30, 2009 averaged 31,647 bbl/d and averaged 59,599 bbl/d in the second quarter of 2009. Production volumes fluctuated throughout the quarter as the Company continued to stabilize and ramp up production, and exceeded the Company's previously issued guidance of 35,000 bbl/d to 55,000 bbl/d for the second quarter of 2009.

North Sea

North Sea crude oil production for the six months ended June 30, 2009 decreased 13% to 41,360 bbl/d from 47,699 bbl/d for the six months ended June 30, 2008. Second quarter North Sea crude oil production decreased 12% to 40,362 bbl/d from 45,830 bbl/d for the second quarter of 2008 and 5% from 42,369 bbl/d for the prior quarter. Production in the second quarter of 2009 was at the high end of the Company's previously issued guidance and reflected planned maintenance shutdowns at two of the Ninian platforms.

Offshore West Africa

Offshore West Africa crude oil production increased 14% to 32,010 bbl/d for the six months ended June 30, 2009 from 28,160 bbl/d for the six months ended June 30, 2008. Second quarter Offshore West Africa crude oil production increased 22% to 33,572 bbl/d from 27,631 bbl/d for the second quarter of 2008, and 10% from 30,431 bbl/d for the prior quarter. During the second quarter of 2009, the fourth and final well in the Baobab Field drilling program was completed and came on stream, and first production was achieved at the Olowi Field in Offshore Gabon.

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)	**Jun 30 2009**	Mar 31 2009	Dec 31 2008
North America – Conventional	**901,053**	761,351	761,351
North America – Oil Sands Mining and Upgrading (SCO)	**1,465,288**	304,544	–
North Sea	**923,645**	1,305,169	558,904
Offshore West Africa	**155,953**	(231,042)	609,444
	3,445,939	2,140,022	1,929,699

OPERATING HIGHLIGHTS – CONVENTIONAL

	Three Months Ended						Six Months Ended			
		Jun 30 2009		Mar 31 2009		Jun 30 2008		**Jun 30 2009**		Jun 30 2008
Crude oil and NGLs ($/bbl) [1]										
Sales price [2]	**$**	**59.56**	$	41.25	$	103.73	**$**	**50.12**	$	91.11
Royalties		**7.27**		3.98		14.82		**5.57**		11.70
Production expense		**16.59**		15.02		16.39		**15.78**		15.58
Netback	**$**	**35.70**	$	22.25	$	72.52	**$**	**28.77**	$	63.83
Natural gas ($/mcf) [1]										
Sales price [2]	**$**	**4.11**	$	5.46	$	9.89	**$**	**4.78**	$	8.83
Royalties [3]		**0.06**		0.72		1.86		**0.39**		1.60
Production expense		**1.05**		1.18		0.94		**1.12**		0.98
Netback	**$**	**3.00**	$	3.56	$	7.09	**$**	**3.27**	$	6.25
Barrels of oil equivalent ($/boe) [1]										
Sales price [2]	**$**	**44.52**	$	37.87	$	84.88	**$**	**41.13**	$	74.86
Royalties		**4.34**		4.14		13.26		**4.24**		10.82
Production expense		**12.21**		11.77		11.60		**11.98**		11.31
Netback	**$**	**27.97**	$	21.96	$	60.02	**$**	**24.91**	$	52.73

(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 the three and six months ended June 30, 2009 reflect the impact of natural gas physical sales contracts and other adjustments and recoveries related to prior periods. Normalized royalties would have been approximately $0.27 per mcf (8% of natural gas revenue) for the three months ended June 30, 2009 and approximately $0.50 per mcf (11% of natural gas revenue) for the six months ended June 30, 2009.

PRODUCT PRICES – CONVENTIONAL

	Three Months Ended						Six Months Ended			
		Jun 30 2009		Mar 31 2009		Jun 30 2008		**Jun 30 2009**		Jun 30 2008
Crude oil and NGLs ($/bbl) [1] [2]										
North America	**$**	**57.97**	$	37.40	$	97.94	**$**	**47.25**	$	85.31
North Sea	**$**	**65.52**	$	54.67	$	129.57	**$**	**60.85**	$	112.75
Offshore West Africa	**$**	**63.00**	$	54.27	$	114.56	**$**	**58.00**	$	105.51
Company average	**$**	**59.56**	$	41.25	$	103.73	**$**	**50.12**	$	91.11
Natural gas ($/mcf) [1] [2]										
North America	**$**	**4.06**	$	5.46	$	9.94	**$**	**4.76**	$	8.87
North Sea	**$**	**3.84**	$	4.28	$	4.27	**$**	**4.06**	$	3.77
Offshore West Africa	**$**	**7.34**	$	6.68	$	8.97	**$**	**7.09**	$	8.44
Company average	**$**	**4.11**	$	5.46	$	9.89	**$**	**4.78**	$	8.83
Company average ($/boe) [1] [2]	**$**	**44.52**	$	37.87	$	84.88	**$**	**41.13**	$	74.86

(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 decreased 45% to average $47.25 per bbl for the six months ended June 30, 2009 from $85.31 per bbl for the six months ended June 30, 2008. Realized crude oil prices decreased 41% to average $57.97 per bbl for the second quarter of 2009 from $97.94 per bbl for the second quarter of 2008, and increased 55% from $37.40 per bbl for the prior quarter. The decreases from the comparable periods in 2008 were primarily a result of decreased WTI benchmark pricing, partially offset by a narrower Heavy Differential and the impact of the weaker Canadian dollar relative to the US dollar. The increase from the prior quarter was primarily the result of increased WTI benchmark pricing and a narrower 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 second quarter of 2009 contributed approximately 138,000 bbl/d of heavy crude oil blends to the Western Canadian Select stream.

North America realized natural gas prices decreased 46% to average $4.76 per mcf for the six months ended June 30, 2009 from $8.87 per mcf for the six months ended June 30, 2008. Realized natural gas prices decreased 59% to average $4.06 per mcf for the second quarter of 2009 from $9.94 per mcf for the second quarter of 2008, and 26% from $5.46 per mcf for the prior quarter. The decreases in natural gas prices from the comparable periods were primarily related to lower benchmark prices due to lower demand and high storage levels in 2009.

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

	Jun 30 2009	Mar 31 2009	Jun 30 2008
Wellhead Price (1) (2)			
Light/medium crude oil and NGLs ($/bbl) (3)	**$ 56.00**	$ 45.97	$ 113.92
Pelican Lake crude oil ($/bbl)	**$ 59.94**	$ 37.50	$ 98.28
Primary heavy crude oil ($/bbl)	**$ 58.08**	$ 37.99	$ 95.39
Thermal heavy crude oil ($/bbl)	**$ 58.22**	$ 31.53	$ 88.72
Natural gas ($/mcf)	**$ 4.06**	$ 5.46	$ 9.94

(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) Light/medium crude oil and NGLs wellhead pricing for the second quarter of 2009 reflected the impact of significant price discounts for certain types of NGLs, including propane and butane.

North Sea

North Sea realized crude oil prices decreased 46% to average $60.85 per bbl for the six months ended June 30, 2009 from $112.75 per bbl for the six months ended June 30, 2008. Realized crude oil prices decreased 49% to average $65.52 per bbl for the second quarter of 2009 from $129.57 per bbl for the second quarter of 2008, and increased 20% from $54.67 per bbl for the prior quarter. The decreases in realized crude oil prices in the North Sea from the comparable periods in 2008 were primarily the result of the declining Brent benchmark pricing, partially offset by the impact of the weaker Canadian dollar. The increase from the prior quarter was primarily the result of the increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices decreased 45% to average $58.00 per bbl for the six months ended June 30, 2009 from $105.51 per bbl for the six months ended June 30, 2008. Realized crude oil prices decreased 45% to average $63.00 per bbl for the second quarter of 2009 from $114.56 per bbl for the second quarter of 2008, and increased 16% from $54.27 per bbl for the prior quarter. The decreases in realized crude oil prices in Offshore West Africa from the comparable periods in 2008 were primarily the result of the declining Brent benchmark pricing, partially offset by the impact of the weaker Canadian dollar. The increase from the prior quarter was primarily the result of the 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			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 8.83**	$ 4.54	$ 17.46	**$ 6.59**	$ 13.52
North Sea	**$ 0.11**	$ 0.13	$ 0.27	**$ 0.12**	$ 0.23
Offshore West Africa	**$ 5.82**	$ 3.73	$ 14.49	**$ 4.62**	$ 15.95
Company average	**$ 7.27**	$ 3.98	$ 14.82	**$ 5.57**	$ 11.70
Natural gas ($/mcf) (1)					
North America (2)	**$ 0.05**	$ 0.73	$ 1.88	**$ 0.39**	$ 1.62
Offshore West Africa	**$ 0.63**	$ 0.46	$ 1.13	**$ 0.56**	$ 1.28
Company average	**$ 0.06**	$ 0.72	$ 1.86	**$ 0.39**	$ 1.60
Company average ($/boe) (1)	**$ 4.34**	$ 4.14	$ 13.26	**$ 4.24**	$ 10.82
Percentage of revenue (3)					
Crude oil and NGLs	**12%**	10%	14%	**11%**	13%
Natural gas (2)	**2%**	13%	19%	**8%**	18%
Boe	**10%**	11%	16%	**10%**	14%

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

(2) Natural gas royalties for the three and six months ended June 30, 2009 reflect the impact of natural gas physical sales contracts and other adjustments and recoveries related to prior periods. Normalized royalties would have been approximately $0.27 per mcf (8% of natural gas revenue) for the three months ended June 30, 2009 and approximately $0.50 per mcf (11% of natural gas revenue) for the six months ended June 30, 2009.

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

North America

North America royalties for the six months ended June 30, 2009, compared to the six months ended June 30, 2008, reflect the impact of the change in the ARF and weaker realized commodity prices.

Crude oil and NGLs royalties averaged approximately 15% of revenues for the second quarter of 2009, compared to 18% for the second quarter in 2008 and 12% in the prior quarter. Crude oil and NGLs royalties per bbl are anticipated to average 10% to 15% of gross revenue for 2009.

Natural gas royalties averaged approximately 2% of revenues for the second quarter of 2009 compared to 19% for the second quarter of 2008 and 13% for the prior quarter. The decrease in natural gas royalty rates for the second quarter of 2009 compared to the prior quarter was due to the impact of low natural gas benchmark pricing, fixed-price natural gas sales contracts that commenced effective April 1, 2009, as well as other adjustments and recoveries from prior periods. Natural gas royalties are anticipated to average 8% to 10% of gross revenue for 2009.

Offshore West Africa

Under the terms of the Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing and capital costs. Royalty rates as a percentage of revenue averaged approximately 9% for the second quarter of 2009 compared to 13% for the second quarter of 2008 and 7% for the prior quarter. Offshore West Africa royalty rates are anticipated to average 6% to 9% of gross revenue for 2009.

PRODUCTION EXPENSE – CONVENTIONAL

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 15.29**	$ 14.60	$ 15.44	**$ 14.93**	$ 14.65
North Sea	**$ 27.36**	$ 22.39	$ 25.61	**$ 25.22**	$ 23.81
Offshore West Africa	**$ 10.45**	$ 11.39	$ 9.79	**$ 10.99**	$ 8.92
Company average	**$ 16.59**	$ 15.02	$ 16.39	**$ 15.78**	$ 15.58
Natural gas ($/mcf) [1]					
North America	**$ 1.04**	$ 1.17	$ 0.93	**$ 1.11**	$ 0.97
North Sea	**$ 1.62**	$ 1.86	$ 2.68	**$ 1.73**	$ 2.50
Offshore West Africa	**$ 1.36**	$ 1.70	$ 1.27	**$ 1.49**	$ 1.26
Company average	**$ 1.05**	$ 1.18	$ 0.94	**$ 1.12**	$ 0.98
Company average ($/boe) [1]	**$ 12.21**	$ 11.77	$ 11.60	**$ 11.98**	$ 11.31

(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 six months ended June 30, 2009 increased 2% to $14.93 per bbl from $14.65 per bbl for the six months ended June 30, 2008. Production expense for the second quarter of 2009 decreased 1% to $15.29 per bbl from $15.44 per bbl for the second quarter of 2008 and increased 5% from $14.60 per bbl for the prior quarter. The increase in production expense per barrel for the second quarter of 2009 was a result of the timing of thermal steam cycles and increased property taxes, partially offset by the lower cost of natural gas for fuel. North America crude oil and NGLs production expense is anticipated to average $15.00 to $15.50 per bbl for 2009.

North America natural gas production expense for the six months ended June 30, 2009 increased 14% to $1.11 per mcf from $0.97 per mcf for the six months ended June 30, 2008. Production expense for the second quarter of 2009 increased 12% to $1.04 per mcf from $0.93 per mcf for the second quarter of 2008 and decreased 11% from $1.17 per mcf for the prior quarter. The increase in production expense per mcf from the comparable periods in 2008 was primarily a result of lower production volumes on the fixed cost portion of production costs. North America natural gas production expense is anticipated to average $1.05 to $1.15 per mcf for 2009.

North Sea

North Sea crude oil production expense increased on a per barrel basis from the prior quarter due to the impact of lower production volumes and higher costs associated with the planned maintenance shutdowns at two of the Ninian platforms. Production expense is anticipated to average $26.50 to $28.50 per bbl for 2009.

Offshore West Africa

Offshore West Africa crude oil production expense decreased on a per barrel basis from the prior quarter due to higher production volumes. Production expense was also impacted by the timing of liftings of each field. Production expense is anticipated to average $12.50 to $14.50 per bbl for 2009.

DEPLETION, DEPRECIATION AND AMORTIZATION – CONVENTIONAL

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Expense ($ millions)	**$ 631**	$ 661	$ 668	**$ 1,292**	$ 1,354
$/boe (1)	**$ 13.07**	$ 13.21	$ 12.88	**$ 13.14**	$ 12.88

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

The decrease in Conventional Depletion, Depreciation and Amortization expense from the prior periods was primarily due to the impact of lower sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION – CONVENTIONAL

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Expense ($ millions)	**$ 18**	$ 17	$ 17	**$ 35**	$ 34
$/boe (1)	**$ 0.36**	$ 0.35	$ 0.33	**$ 0.35**	$ 0.32

(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			Six Months Ended	
($/bbl) (1)	**Jun 30 2009**	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
SCO sales price (2)	**$ 65.40**	$ –	$ –	**$ 65.40**	$ –
Bitumen value for royalty purposes	**$ 54.00**	$ –	$ –	**$ 54.00**	$ –
Bitumen royalties (3)	**$ 0.76**	$ –	$ –	**$ 0.76**	$ –

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

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

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

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.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2009**	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Cash costs, excluding natural gas costs	**$ 159**	$ –	$ –	**$ 159**	$ –
Natural gas costs	**23**	–	–	**23**	–
Total cash production costs	**$ 182**	$ –	$ –	**$ 182**	$ –

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2009**	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Cash costs, excluding natural gas costs	**$ 37.15**	$ –	$ –	**$ 37.15**	$ –
Natural gas costs	**5.50**	–	–	**5.50**	–
Total cash production costs	**$ 42.65**	$ –	$ –	**$ 42.65**	$ –
Sales (bbl/d)	**46,844**	–	–	**23,551**	–

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

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

Production expense in the second quarter of 2009 reflected the effects of the commencement of operations. Total cash production costs averaged $42.65 per bbl in the second quarter of 2009, and are expected to average $35.00 to $40.00 per bbl for the year.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2009**	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Depreciation, depletion and amortization	**$ 36**	$ 2	$ –	**$ 38**	$ –
Asset retirement obligation accretion	**6**	2	–	**8**	–
Total	**$ 42**	$ 4	$ –	**$ 46**	$ –

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2009**	Mar 31 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Depreciation, depletion and amortization	**$ 8.51**	$ –	$ –	**$ 9.02**	$ –
Asset retirement obligation accretion	**1.47**	–	–	**1.96**	–
Total	**$ 9.98**	$ –	$ –	**$ 10.98**	$ –

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

During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs have ceased, and depletion, depreciation and amortization of these assets has commenced.

MIDSTREAM

($ millions)	Three Months Ended Jun 30 2009	Three Months Ended Mar 31 2009	Three Months Ended Jun 30 2008	Six Months Ended Jun 30 2009	Six Months Ended Jun 30 2008
Revenue	**$ 17**	$ 19	$ 20	**$ 36**	$ 40
Production expense	**5**	5	8	**10**	13
Midstream cash flow	**12**	14	12	**26**	27
Depreciation	**2**	2	2	**4**	4
Segment earnings before taxes	**$ 10**	$ 12	$ 10	**$ 22**	$ 23

Midstream operating results were consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended Jun 30 2009	Three Months Ended Mar 31 2009	Three Months Ended Jun 30 2008	Six Months Ended Jun 30 2009	Six Months Ended Jun 30 2008
Expense ($ millions)	**$ 47**	$ 47	$ 45	**$ 94**	$ 88
$/boe (1)	**$ 0.88**	$ 0.95	$ 0.87	**$ 0.91**	$ 0.83

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

Administration expense for the second quarter of 2009 was comparable to the prior periods. Administration expense on a boe basis decreased in the second quarter of 2009 compared to the prior quarter due to increased sales volumes associated with the commencement of Horizon.

STOCK-BASED COMPENSATION EXPENSE

($ millions)	Three Months Ended Jun 30 2009	Three Months Ended Mar 31 2009	Three Months Ended Jun 30 2008	Six Months Ended Jun 30 2009	Six Months Ended Jun 30 2008
Expense	**$ 92**	$ 4	$ 459	**$ 96**	$ 459

The Company recorded a $96 million ($70 million after-tax) stock-based compensation expense for the six months ended June 30, 2009 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 the 26% increase in the Company's share price, including a $92 million ($67 million after-tax) stock-based compensation expense for the three months ended June 30, 2009 (Company's share price as at: June 30, 2009 – $61.19; March 31, 2009 – C$48.91; December 31, 2008 – C$48.75; June 30, 2008 – C$100.84). For the six months ended June 30, 2009, the Company recorded a $7 million recovery on previously capitalized stock-based compensation to Oil Sands Mining and Upgrading (June 30, 2008 – $132 million capitalized). 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 June 30, 2009.

For the six months ended June 30, 2009, the Company paid $43 million for stock options surrendered for cash settlement (June 30, 2008 – $184 million).

INTEREST EXPENSE

($ millions, except per boe amounts)	Three Months Ended Jun 30 2009	Mar 31 2009	Jun 30 2008	Six Months Ended Jun 30 2009	Jun 30 2008
Expense, gross	**$ 130**	$ 143	$ 141	**$ 273**	$ 301
Less: capitalized interest, Oil Sands Mining and Upgrading	**6**	86	110	**92**	221
Expense, net	**$ 124**	$ 57	$ 31	**$ 181**	$ 80
$/boe (1)	**$ 2.36**	$ 1.14	$ 0.60	**$ 1.76**	$ 0.76
Average effective interest rate	**4.1%**	4.4%	4.8%	**4.2%**	5.2%

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

Gross interest expense and the Company's average effective interest rate decreased from the comparable periods primarily due to lower variable interest rates.

During the first quarter of 2009, interest capitalization ceased on Horizon Phase 1, 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 Jun 30 2009	Mar 31 2009	Jun 30 2008	Six Months Ended Jun 30 2009	Jun 30 2008
Crude oil and NGLs financial instruments	**$ (362)**	$ (585)	$ 944	**$ (947)**	$ 1,407
Natural gas financial instruments	**(1)**	(32)	10	**(33)**	(37)
Foreign currency contracts	**73**	(24)	–	**49**	–
Realized (gain) loss	**$ (290)**	$ (641)	$ 954	**$ (931)**	$ 1,370
Crude oil and NGLs financial instruments	**$ 1,020**	$ 483	$ 1,380	**$ 1,503**	$ 1,431
Natural gas financial instruments	**(13)**	(24)	38	**(37)**	97
Foreign currency contracts and interest rate swaps	**(61)**	4	(3)	**(57)**	(5)
Unrealized loss	**$ 946**	$ 463	$ 1,415	**$ 1,409**	$ 1,523
Net loss (gain)	**$ 656**	$ (178)	$ 2,369	**$ 478**	$ 2,893

Complete details related to outstanding derivative financial instruments at June 30, 2009 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 loss of $1,409 million ($996 million after-tax) on its risk management activities for the six months ended June 30, 2009, including a $946 million ($676 million after-tax) net unrealized loss for the second quarter of 2009 (March 31, 2009 – unrealized loss of $463 million, $320 million after-tax; June 30, 2008 – unrealized loss of $1,415 million, $997 million after-tax).

FOREIGN EXCHANGE

($ millions)	Three Months Ended Jun 30 2009	Mar 31 2009	Jun 30 2008	Six Months Ended Jun 30 2009	Jun 30 2008
Net realized loss (gain)	**$ 74**	$ (15)	$ (11)	**$ 59**	$ (23)
Net unrealized (gain) loss [1]	**(320)**	138	(20)	**(182)**	106
Net (gain) loss	**$ (246)**	$ 123	$ (31)	**$ (123)**	$ 83

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

The net unrealized foreign exchange gain for the six months ended June 30, 2009 was primarily due to the strengthening of the Canadian dollar with respect to the US dollar debt, offset by the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling. Also included in net unrealized (gain) loss for the respective periods was the impact of cross currency swaps (three months ended June 30, 2009 – unrealized loss of $186 million, March 31, 2009 – unrealized gain of $68 million, June 30, 2008 – unrealized loss of $17 million; six months ended June 30, 2009 – unrealized loss of $118 million, June 30, 2008 – unrealized gain of $58 million). The net realized foreign exchange loss for the six months ended June 30, 2009 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 second quarter at US$0.8602 (March 31, 2009 – US$0.7935; December 31, 2008 – US$0.8166; June 30, 2008 – US$0.9817).

TAXES

($ millions, except income tax rates)	Three Months Ended Jun 30 2009	Mar 31 2009	Jun 30 2008	Six Months Ended Jun 30 2009	Jun 30 2008
Current	**$ 49**	$ 7	$ 96	**$ 56**	$ 166
Deferred	**(2)**	(3)	(34)	**(5)**	(55)
Taxes other than income tax	**$ 47**	$ 4	$ 62	**$ 51**	$ 111
North America [1]	**$ 5**	$ 5	$ 6	**$ 10**	$ 27
North Sea	**65**	98	111	**163**	207
Offshore West Africa	**17**	14	34	**31**	72
Current income tax	**87**	117	151	**204**	306
Future income tax recovery	**(201)**	(56)	(301)	**(257)**	(221)
	(114)	61	(150)	**(53)**	85
Income tax rate and other legislative changes [2] [3]	**–**	19	–	**19**	41
	$ (114)	$ 80	$ (150)	**$ (34)**	$ 126
Effective income tax rate before non-recurring benefits [4]	**–**	21.9%	30.2%	**–**	27.1%

(1) Includes conventional crude oil and natural gas, Midstream, and Oil Sands Mining and Upgrading segments.

(2) Includes the effect of a one time recovery of $19 million due to British Columbia corporate income tax rate reductions substantively enacted or enacted during the first quarter of 2009.

(3) Includes the effect of a one time recovery of $19 million due to British Columbia corporate income tax rate reductions and $22 million due to Côte d'Ivoire corporate income tax rate reductions substantively enacted or enacted during the first quarter of 2008.

(4) For the three and six months ended June 30, 2009, the Company's effective tax rate would have been negative reflecting the combined effects of jurisdictional tax rate adjustments and the impact of the non-taxable portion of unrealized foreign exchange gains on US dollar denominated debt.

CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Jun 30 2009	Mar 31 2009	Jun 30 2008	Six Months Ended Jun 30 2009	Jun 30 2008
Expenditures on property, plant and equipment					
Net property (dispositions) acquisitions	**$ (2)**	$ 27	$ 263	**$ 25**	$ 255
Land acquisition and retention	**18**	13	24	**31**	36
Seismic evaluations	**11**	28	18	**39**	45
Well drilling, completion and equipping	**194**	498	286	**692**	738
Production and related facilities	**230**	290	270	**520**	589
Total net reserve replacement expenditures	**451**	856	861	**1,307**	1,663
Oil Sands Mining and Upgrading:					
Horizon Phase 1 construction costs	**(59)**	128	875	**69**	1,540
Horizon Phase 1 commissioning and other costs	**46**	156	48	**202**	138
Horizon Phases 2/3 construction costs	**22**	19	82	**41**	159
Capitalized interest, stock-based compensation and other	**(4)**	79	247	**75**	356
Sustaining capital	**4**	–	–	**4**	–
Total Oil Sands Mining and Upgrading [2]	**9**	382	1,252	**391**	2,193
Midstream	**–**	5	3	**5**	4
Abandonments [3]	**10**	9	7	**19**	13
Head office	**3**	4	4	**7**	7
Total net capital expenditures	**$ 473**	$ 1,256	$ 2,127	**$ 1,729**	$ 3,880
By segment					
North America	**$ 270**	$ 599	$ 617	**$ 869**	$ 1,280
North Sea	**40**	42	79	**82**	124
Offshore West Africa	**141**	215	164	**356**	258
Other	**–**	–	1	**–**	1
Oil Sands Mining and Upgrading	**9**	382	1,252	**391**	2,193
Midstream	**–**	5	3	**5**	4
Abandonments [3]	**10**	9	7	**19**	13
Head office	**3**	4	4	**7**	7
Total	**$ 473**	$ 1,256	$ 2,127	**$ 1,729**	$ 3,880

(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 six months ended June 30, 2009 were $1,729 million compared to $3,880 million for the six months ended June 30, 2008. Net capital expenditures for the second quarter of 2009 were $473 million compared to $2,127 million for the second quarter of 2008 and $1,256 million for the prior quarter. The decrease in capital expenditures in the second quarter of 2009 primarily reflects the completion of Horizon Phase 1 construction. Capital expenditures were also impacted by the effects of an overall strategic reduction in the North America natural gas drilling program.

Drilling Activity (number of wells)

	Three Months Ended			Six Months Ended	
	Jun 30 2009	Mar 30 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Net successful natural gas wells	**-**	64	5	**64**	166
Net successful crude oil wells	**94**	93	93	**187**	266
Dry wells	**4**	15	6	**19**	17
Stratigraphic test / service wells	**7**	236	11	**243**	26
Total	**105**	408	115	**513**	475
Success rate (excluding stratigraphic test / service wells)	**96%**	91%	94%	**93%**	96%

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 52% of the total capital expenditures for the six months ended June 30, 2009 compared to approximately 34% for the six months ended June 30, 2008.

During the second quarter of 2009, the Company targeted 97 net crude oil wells. These wells were concentrated in the Company's crude oil Northern Plains region where 48 heavy crude oil wells, 19 Pelican Lake crude oil wells, and 30 thermal crude oil wells were drilled. The Company did not target any net natural gas wells during the same period.

The Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in recent years and as a result of royalty changes under the ARF, natural gas drilling activities have been reduced to manage overall capital spending. Deferred natural gas well locations have been retained in the Company's prospect inventory.

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 second quarter of 2009 averaged approximately 63,000 bbl/d compared to approximately 67,000 bbl/d for the second quarter of 2008 and approximately 82,000 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 fourth quarter of 2008. During the first quarter of 2009, operational issues on one of the pads has caused steaming to cease on all well pads in the Primrose East project area and the Company is continuing to work on resolving the issues.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout the second quarter of 2009. Drilling consisted of 19 horizontal wells in the second quarter. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 36,000 bbl/d for the second quarter of 2009, compared to 37,000 bbl/d for the second quarter of 2008 and the prior quarter.

For the third quarter of 2009, the Company's overall planned drilling activity in North America is expected to be comprised of 24 natural gas wells and 238 crude oil wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

With construction completed, Horizon Phase 1 assets are now available for their intended use. Accordingly, capitalization of all associated development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs have ceased, and depletion, depreciation and amortization of these assets has commenced. Capital expenditures during the second quarter of 2009 reflected the recovery of holdbacks and settlement of various construction contracts.

North Sea

In the second quarter of 2009, the Company commenced planned maintenance shutdowns at two of the Ninian platforms. These shutdowns were completed early in the third quarter of 2009, on schedule and on budget. The Deep Banff exploration well did not find commercial hydrocarbons and was abandoned early in the third quarter.

Offshore West Africa

During the second quarter of 2009, 1.0 net crude oil wells and an injection well were drilled at the Olowi Field in Offshore Gabon, with a further oil well in progress at the end of the quarter.

At Baobab, the drilling rig was released early in the second quarter, having completed the four well drilling program. At the Olowi Field, first crude oil production was achieved in April 2009, with three wells on production by June 30, 2009. Construction of the wellhead tower decks was also completed during the second quarter and they are currently being transported to Gabon for installation in the third quarter of 2009.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Jun 30 2009**		Mar 31 2009		Dec 31 2008		Jun 30 2008
Working capital (deficit) (1)	**$**	**(113)**	$	237	$	392	$	(3,180)
Long-term debt (2) (3)	**$**	**11,987**	$	13,132	$	13,016	$	11,040
Share capital	**$**	**2,816**	$	2,809	$	2,768	$	2,754
Retained earnings		**15,697**		15,592		15,344		10,847
Accumulated other comprehensive income		**75**		315		262		6
Shareholders' equity	**$**	**18,588**	$	18,716	$	18,374	$	13,607
Debt to book capitalization (3) (4)		**39%**		41%		41%		45%
Debt to market capitalization (3) (5)		**27%**		33%		33%		17%
After tax return on average common shareholders' equity (6)		**30%**		28%		33%		14%
After tax return on average capital employed (3) (7)		**18%**		17%		19%		8%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Includes the current portion of long-term debt (June 30, 2009 – $nil; March 31, 2009 – $205 million; December 31, 2008 – $420 million; June 30, 2008 – $nil).

(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. Average capital employed is the average shareholders' equity and current and long-term debt for the period, including $12,209 million in average capital employed related to the Oil Sands Mining and Upgrading assets (March 31, 2009 – $11,537 million; December 31, 2008 – $10,678 million; June 30, 2008 – $8,781 million).

At June 30, 2009, 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, 2008 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 uncertainties created by the worldwide financial and economic events over the past several quarters appear to be lessening in intensity as liquidity is returning to the capital markets and financial institutions re-establish confidence in their balance sheets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its 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 June 30, 2009, the Company had $1,749 million of available credit under its bank credit facilities, which together with cash flow from operating activities to be generated in 2009 supported by its commodity risk management program and the ability to actively manage the capital expenditure programs, is forecasted to be sufficient to repay the non-revolving bank credit facility of $1,370 million maturing October 2009. Subsequent to June 30, 2009, $350 million was repaid on this facility. 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 and BBB with a stable outlook by Standard & Poor's.

Further details related to the Company's long-term debt at June 30, 2009 are discussed in note 4 to the Company's unaudited interim consolidated financial statements.

Long-term debt was $11,987 million at June 30, 2009, resulting in a debt to book capitalization ratio of 39% (March 31, 2009 – 41%; December 31, 2008 – 41%; June 30, 2008 – 45%). This ratio is near the midpoint of the 35% to 45% range targeted by management, including the impact of capital spending on the Horizon Project. 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 2009 and 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 June 30, 2009, in accordance with the policy, approximately 6% of budgeted crude oil volumes were hedged using collars for 2009 and approximately 12% of budgeted crude oil volumes and approximately 17% of budgeted natural gas volumes were hedged using collars for 2010. In addition, 92,000 bbl/d of crude oil volumes are protected by put options for the remainder of 2009 at a strike price of US$100.00 per bbl.

Further details related to the Company's commodity related derivative financial instruments outstanding at June 30, 2009 are discussed in note 11 to the Company's unaudited interim consolidated financial statements.

Share capital

As at June 30, 2009, there were 542,058,000 common shares outstanding and 27,871,000 stock options outstanding. As at August 4, 2009, the Company had 542,110,000 common shares outstanding and 27,648,000 stock options outstanding.

In March 2009, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.42 per common share for 2009. The increase represented a 5% increase from 2008, 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.

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 June 30, 2009, 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 June 30, 2009:

($ millions)	Remaining 2009	2010	2011	2012	2013	Thereafter
Product transportation and pipeline	$ 115	$ 188	$ 158	$ 134	$ 123	$ 1,165
Offshore equipment operating lease	$ 101	$ 138	$ 137	$ 111	$ 111	$ 378
Offshore drilling	$ 82	$ 59	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 9	$ 10	$ 16	$ 17	$ 26	$ 5,799
Long-term debt (2)	$ 1,369	$ 400	$ 465	$ 407	$ 865	$ 6,387
Interest expense (3)	$ 263	$ 520	$ 498	$ 458	$ 407	$ 5,691
Office leases	$ 12	$ 29	$ 23	$ 2	$ 2	$ 2
Other	$ 180	$ 185	$ 16	$ 9	$ 7	$ 19

(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 2009 – 2013 represent the minimum required expenditures 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 $2,125 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 June 30, 2009.

Legal proceedings

The Company is defendant and plaintiff in a number of legal actions. In addition, the Company is subject to certain contractor construction claims related to Horizon. 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 judgements, 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, 2008.

For the impact of new accounting standards related to goodwill and intangible assets, refer to note 2 of the unaudited interim consolidated financial statements as at June 30, 2009.

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 Senior 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. Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, impairment testing, capitalized interest and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. The Company is continuing to perform the necessary research to develop and document IFRS policies to address the major differences noted. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable. In addition, IFRS is expected to change prior to adoption in 2011, and the impact of these potential changes is not known. Included in the IFRS changes are amendments to IFRS 1 "Additional Exemptions for First-time Adopters" issued in July 2009 by the IASB, which prescribes transition exemptions for oil and gas companies following full cost accounting. The transition exemptions allow 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 the transition exemptions.

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 second quarter of 2009, 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	$ 119	$ 0.22	$ 89	$ 0.17
Including financial derivatives	$ 85 – 92	$ 0.16 – 0.17	$ 62 – 67	$ 0.12
Natural gas – AECO C$0.10/mcf (1)				
Excluding financial derivatives	$ 30	$ 0.06	$ 22	$ 0.04
Including financial derivatives	$ 26	$ 0.05	$ 19	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 138	$ 0.26	$ 77	$ 0.14
Natural gas – 10 mmcf/d	$ 10	$ 0.02	$ 2	$ 0.01
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 90 – 92	$ 0.17	$ 7	$ 0.01
Interest rate change – **1%**	$ 18	$ 0.03	$ 18	$ 0.03

(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)	**Jun 30 2009**	Dec 31 2008
ASSETS		
Current assets		
Cash and cash equivalents	**$ 25**	$ 27
Accounts receivable	**1,179**	1,059
Inventory, prepaids and other	**590**	455
Current portion of other long-term assets (note 3)	**479**	1,851
	2,273	3,392
Property, plant and equipment (note 13)	**39,430**	38,966
Other long-term assets (note 3)	**59**	292
	$ 41,762	$ 42,650
LIABILITIES		
Current liabilities		
Accounts payable	**$ 327**	$ 383
Accrued liabilities	**1,727**	1,802
Future income tax	**64**	585
Current portion of long-term debt (note 4)	**-**	420
Current portion of other long-term liabilities (note 5)	**268**	230
	2,386	3,420
Long-term debt (note 4)	**11,987**	12,596
Other long-term liabilities (note 5)	**1,390**	1,124
Future income tax	**7,411**	7,136
	23,174	24,276
SHAREHOLDERS' EQUITY		
Share capital (note 7)	**2,816**	2,768
Retained earnings	**15,697**	15,344
Accumulated other comprehensive income (note 8)	**75**	262
	18,588	18,374
	$ 41,762	$ 42,650

Commitments (note 12)

Consolidated Statements of Earnings (Loss)

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended **Jun 30 2009**	Three Months Ended Jun 30 2008	Six Months Ended **Jun 30 2009**	Six Months Ended Jun 30 2008
Revenues	**$ 2,750**	$ 5,112	**$ 4,936**	$ 9,079
Less: royalties	**(212)**	(688)	**(411)**	(1,137)
Revenues, net of royalties	**2,538**	4,424	**4,525**	7,942
Expenses				
Production	**773**	610	**1,355**	1,197
Transportation and blending	**309**	689	**626**	1,174
Depletion, depreciation and amortization	**664**	670	**1,310**	1,358
Asset retirement obligation accretion (note 5)	**24**	17	**43**	34
Administration	**47**	45	**94**	88
Stock-based compensation expense (note 5)	**92**	459	**96**	459
Interest, net	**124**	31	**181**	80
Risk management activities (note 11)	**656**	2,369	**478**	2,893
Foreign exchange (gain) loss	**(246)**	(31)	**(123)**	83
	2,443	4,859	**4,060**	7,366
Earnings (loss) before taxes	**95**	(435)	**465**	576
Taxes other than income tax	**47**	62	**51**	111
Current income tax expense (note 6)	**87**	151	**204**	306
Future income tax recovery (note 6)	**(201)**	(301)	**(257)**	(221)
Net earnings (loss)	**$ 162**	$ (347)	**$ 467**	$ 380
Net earnings (loss) per common share (note 10)				
Basic and diluted	**$ 0.30**	$ (0.65)	**$ 0.86**	$ 0.70

Consolidated Statements of Shareholders' Equity

(millions of Canadian dollars, unaudited)	Six Months Ended **Jun 30 2009**	Jun 30 2008
Share capital (note 7)		
Balance – beginning of period	**$ 2,768**	$ 2,674
Issued upon exercise of stock options	**18**	14
Previously recognized liability on stock options exercised for common shares	**30**	66
Balance – end of period	**2,816**	2,754
Retained earnings		
Balance – beginning of period	**15,344**	10,575
Net earnings	**467**	380
Dividends on common shares (note 7)	**(114)**	(108)
Balance – end of period	**15,697**	10,847
Accumulated other comprehensive income (note 8)		
Balance – beginning of period	**262**	72
Other comprehensive loss, net of taxes	**(187)**	(66)
Balance – end of period	**75**	6
Shareholders' equity	**$ 18,588**	$ 13,607

Consolidated Statements of Comprehensive Income (Loss)

(millions of Canadian dollars, unaudited)	Three Months Ended **Jun 30 2009**	Three Months Ended Jun 30 2008	Six Months Ended **Jun 30 2009**	Six Months Ended Jun 30 2008
Net earnings (loss)	**$ 162**	$ (347)	**$ 467**	$ 380
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized loss during the period, net of taxes of $2 million (2008 – $13 million) – three months ended; $4 million (2008 – $15 million) – six months ended	**(13)**	(89)	**(30)**	(65)
Reclassification to net earnings (loss), net of taxes of $nil (2008 – $1 million) – three months ended; $1 million (2008 – $7 million) – six months ended	**(5)**	3	**(8)**	(14)
	(18)	(86)	**(38)**	(79)
Foreign currency translation adjustment				
Translation of net investment	**(222)**	(3)	**(149)**	13
Other comprehensive loss, net of taxes	**(240)**	(89)	**(187)**	(66)
Comprehensive income (loss)	**$ (78)**	$ (436)	**$ 280**	$ 314

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Three Months Ended **Jun 30 2009**	Three Months Ended Jun 30 2008	Six Months Ended **Jun 30 2009**	Six Months Ended Jun 30 2008
Operating activities				
Net earnings (loss)	**$ 162**	$ (347)	**$ 467**	$ 380
Non-cash items				
Depletion, depreciation and amortization	**664**	670	**1,310**	1,358
Asset retirement obligation accretion	**24**	17	**43**	34
Stock-based compensation	**92**	459	**96**	459
Unrealized risk management loss	**946**	1,415	**1,409**	1,523
Unrealized foreign exchange (gain) loss	**(320)**	(20)	**(182)**	106
Deferred petroleum revenue tax recovery	**(2)**	(34)	**(5)**	(55)
Future income tax recovery	**(201)**	(301)	**(257)**	(221)
Other	**7**	6	**(6)**	19
Abandonment expenditures	**(10)**	(7)	**(19)**	(13)
Net change in non-cash working capital	**(110)**	314	**(113)**	148
	1,252	2,172	**2,743**	3,738
Financing activities				
Repayment of bank credit facilities, net	**(398)**	(68)	**(506)**	(1,240)
Repayment of senior unsecured notes	**(34)**	(31)	**(34)**	(31)
Issue of US dollar debt securities	**-**	-	**-**	1,223
Issue of common shares on exercise of stock options	**2**	5	**18**	14
Dividends on common shares	**(57)**	(54)	**(111)**	(100)
Net change in non-cash working capital	**32**	25	**(4)**	30
	(455)	(123)	**(637)**	(104)
Investing activities				
Expenditures on property, plant and equipment	**(470)**	(2,121)	**(1,717)**	(3,877)
Net proceeds on sale of property, plant and equipment	**7**	1	**7**	10
Net expenditures on property, plant and equipment	**(463)**	(2,120)	**(1,710)**	(3,867)
Net change in non-cash working capital	**(319)**	66	**(398)**	234
	(782)	(2,054)	**(2,108)**	(3,633)
Increase (decrease) in cash and cash equivalents	**15**	(5)	**(2)**	1
Cash and cash equivalents – beginning of period	**10**	27	**27**	21
Cash and cash equivalents – end of period	**$ 25**	$ 22	**$ 25**	$ 22
Interest paid	**$ 92**	$ 132	**$ 276**	$ 278
Taxes paid (recovered)				
Taxes other than income tax	**$ 25**	$ 24	**$ -**	$ 55
Current income tax	**$ (2)**	$ (108)	**$ 41**	$ (55)

Notes to the consolidated financial statements
(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

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, 2008, except as described in note 2. 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, 2008.

During 2009, Horizon Oil Sands ("Horizon") Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs have ceased, and depletion, depreciation and amortization of these assets has commenced. In addition, the Company has recognized additional asset retirement obligations related to its oil sands mining operations and tailings ponds (note 5). All Horizon related financial results are included in the "Oil Sands Mining and Upgrading" segment.

Comparative Figures

Certain prior period figures have been reclassified to conform to the presentation adopted in 2009.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2009, the Company adopted the following new accounting standard issued by the Canadian Institute of Chartered Accountants ("CICA"):

- **Goodwill and Intangible Assets** – Section 3064 – "Goodwill and Intangible Assets" replaces Section 3062 – "Goodwill and Other Intangible Assets" and Section 3450 – "Research and Development Costs". In addition, EIC-27 – "Revenue and Expenditures during the Pre-Operating Period" has been withdrawn. The new standard addresses when an internally generated intangible asset meets the definition of an asset. The adoption of this standard, which was adopted retroactively without restatement, did not have an impact on the Company's financial statements.

In February 2008, the CICA's 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 is currently assessing which accounting policies will be affected by the change to IFRS and the potential impact of these changes on its financial position and results of operations.

3. OTHER LONG–TERM ASSETS

	Jun 30 2009	Dec 31 2008
Risk management (note 11)	**$ 509**	$ 2,119
Other	**29**	24
	538	2,143
Less: current portion	**479**	1,851
	$ 59	$ 292

4. LONG–TERM DEBT

	Jun 30 2009	Dec 31 2008
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	**$ 2,622**	$ 4,073
Medium-term notes	**1,200**	1,200
	3,822	5,273
US dollar denominated debt		
US dollar bank credit facilities (bankers' acceptances)		
(2009 - US$750 million; 2008 - US$nil)	**872**	-
Senior unsecured notes (2009 - US$nil; 2008 - US$31 million)	**-**	38
US dollar debt securities (2009 - US$6,300 million; 2008 - US$6,300 million)	**7,324**	7,715
Less: original issue discount on senior unsecured notes and US dollar debt securities (1)	**(23)**	(23)
	8,173	7,730
Fair value of interest rate swaps on US dollar debt securities (2)	**44**	68
	8,217	7,798
Long-term debt before transaction costs	**12,039**	13,071
Less: transaction costs (1) (3)	**(52)**	(55)
	11,987	13,016
Less: current portion	**-**	420
	$ 11,987	$ 12,596

(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 $44 million (2008 - $68 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 June 30, 2009, the Company had in place unsecured bank credit facilities of $5,329 million, comprised of:

- a $200 million demand credit facility;
- a non-revolving syndicated credit facility of $1,370 million maturing October 2009;
- 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 has $1,370 million remaining on the non-revolving syndicated credit facility maturing October 2009 related to the acquisition of Anadarko Canada Corporation. During 2009, the Company plans to fully retire this facility from its existing borrowing capacity under its other long-term bank credit facilities of $1,648 million supported by cash flow from operating activities, including the commodity risk management activities. Subsequent to June 30, 2009, $350 million was repaid on this facility.

During the second quarter of 2009, the Company renegotiated its demand credit facility, increasing it to $200 million.

The Company's weighted average interest rate on long-term debt outstanding as at June 30, 2009 was 4.3% (December 31, 2008 – 4.6%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $384 million, including $300 million related to Horizon, were outstanding at June 30, 2009.

Medium-term notes

The Company has $2,600 million remaining on its outstanding $3,000 million base shelf prospectus filed in September 2007 that allows for the issue of medium-term notes in Canada until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

Senior unsecured notes

During the second quarter of 2009, US$31 million of senior unsecured notes were repaid.

US dollar debt securities

The Company has US$1,800 million remaining on its outstanding US$3,000 million base shelf prospectus filed in September 2007 that allows for the issue of US dollar debt securities in the United States until October 2009. If issued, these securities will bear interest as determined at the date of issuance.

5. OTHER LONG – TERM LIABILITIES

	Jun 30 2009	Dec 31 2008
Asset retirement obligations	**$ 1,363**	$ 1,064
Stock-based compensation	**187**	171
Other	**108**	119
	1,658	1,354
Less: current portion	**268**	230
	$ 1,390	$ 1,124

Asset retirement obligations

At June 30, 2009, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $5,877 million (December 31, 2008 – $4,474 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 7.0% (December 31, 2008 – 6.7%). A reconciliation of the discounted asset retirement obligations is as follows:

	Six Months Ended Jun 30, 2009	Year Ended Dec 31, 2008
Balance – beginning of period	**$ 1,064**	$ 1,074
Liabilities incurred [(1) (2)]	**298**	18
Liabilities acquired	**-**	3
Liabilities settled	**(19)**	(38)
Asset retirement obligation accretion	**43**	71
Revision of estimates	**-**	(156)
Foreign exchange	**(23)**	92
Balance – end of period	**$ 1,363**	$ 1,064

(1) During the first quarter of 2009, the Company recognized additional asset retirement obligations related to Horizon (discounted – $246 million, undiscounted – $1,350 million).

(2) During the second quarter of 2009, the Company recognized additional asset retirement obligations related to Gabon, Offshore West Africa (discounted – $46 million, undiscounted – $93 million).

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.

	Six Months Ended Jun 30, 2009	Year Ended Dec 31, 2008
Balance – beginning of period	**$ 171**	$ 529
Stock-based compensation expense (recovery)	**96**	(52)
Cash payments for options surrendered	**(43)**	(207)
Transferred to common shares	**(30)**	(76)
Recovery to Oil Sands Mining and Upgrading	**(7)**	(23)
Balance – end of period	**187**	171
Less: current portion	**181**	159
	$ 6	$ 12

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Six Months Ended	
	Jun 30 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Current income tax – North America [(1)]	**$ 5**	$ 6	**$ 10**	$ 27
Current income tax – North Sea	**65**	111	**163**	207
Current income tax – Offshore West Africa	**17**	34	**31**	72
Current income tax expense	**87**	151	**204**	306
Future income tax recovery	**(201)**	(301)	**(257)**	(221)
Income tax (recovery) expense	**$ (114)**	$ (150)	**$ (53)**	$ 85

(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, North America and North Sea current income taxes will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During the first quarter of 2009, substantively enacted income tax rate changes resulted in a reduction of future income tax liabilities of $19 million in British Columbia (2008 – $19 million reduction in British Columbia, $22 million reduction in Côte d'Ivoire).

7. SHARE CAPITAL

	Six Months Ended Jun 30, 2009	
Issued Common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**540,991**	**$ 2,768**
Issued upon exercise of stock options	**1,067**	**18**
Previously recognized liability on stock options exercised	**-**	**30**
Balance – end of period	**542,058**	**$ 2,816**

Dividend policy

In March 2009, the Board of Directors set the regular quarterly dividend at $0.105 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.

Stock options

	Six Months Ended Jun 30, 2009	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**30,962**	**$ 51.94**
Granted	**340**	**$ 52.78**
Surrendered for cash settlement	**(1,456)**	**$ 20.30**
Exercised for common shares	**(1,067)**	**$ 16.95**
Forfeited	**(908)**	**$ 58.39**
Outstanding – end of period	**27,871**	**$ 54.73**
Exercisable – end of period	**9,103**	**$ 48.91**

8. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Six Months Ended	
	Jun 30 2009	Jun 30 2008
Derivative financial instruments designated as cash flow hedges	**$ 81**	$ 22
Foreign currency translation adjustment	**(6)**	(16)
	$ 75	$ 6

9. CAPITAL DISCLOSURES

As required by Canadian GAAP, the Company must provide certain disclosures regarding its objectives, policies and processes for managing capital, as well as provide certain quantitative data about capital. As the Company does not have any externally imposed regulatory capital requirements, for the purposes of this disclosure, 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 near the midpoint of the target range at 39% including the impact of capital spending on the Horizon Project.

Readers are cautioned that as the debt to book capitalization ratio has no defined meaning under GAAP, this financial measure may not be comparable to similar measures provided by other reporting entities. Further, there can be 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 at some point in the future.

	Jun 30 2009	Dec 31 2008
Long-term debt [(1)]	**$ 11,987**	$ 13,016
Total shareholders' equity	**$ 18,588**	$ 18,374
Debt to book capitalization	**39%**	41%

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

10. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	Jun 30 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Weighted average common shares outstanding (thousands) – basic and diluted	**541,998**	540,632	**541,626**	540,425
Net earnings (loss) – basic and diluted	**$ 162**	$ (347)	**$ 467**	$ 380
Net earnings (loss) per common share – basic and diluted	**$ 0.30**	$ (0.65)	**$ 0.86**	$ 0.70

11. FINANCIAL INSTRUMENTS

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

	Jun 30, 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	**$ -**	**$ 25**	**$ -**
Accounts receivable	**1,179**	**-**	**-**
Risk management	**-**	**509**	**-**
Accounts payable	**-**	**-**	**(327)**
Accrued liabilities	**-**	**-**	**(1,727)**
Other long-term liabilities	**-**	**-**	**(96)**
Long-term debt	**-**	**-**	**(11,987)**
	$ 1,179	**$ 534**	**$ (14,137)**

	Dec 31, 2008		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ -	$ 27	$ -
Accounts receivable	1,059	-	-
Risk management	-	2,119	-
Accounts payable	-	-	(383)
Accrued liabilities	-	-	(1,802)
Other long-term liabilities	-	-	(105)
Long-term debt (1)	-	-	(13,016)
	$ 1,059	$ 2,146	$ (15,306)

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

The carrying value of the Company's financial instruments approximates their fair value, except for fixed-rate long-term debt as noted below:

	Jun 30, 2009		Dec 31, 2008	
	Carrying value	**Fair value**	Carrying value	Fair value
Fixed-rate long-term debt (1)	**$ 8,493**	**$ 8,690**	$ 8,943	$ 7,649

(1) 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 $44 million (2008 - $68 million) to reflect the fair value impact of hedge accounting.

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 and/or third party indications. 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 has relied primarily 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:

	Six Months Ended Jun 30, 2009	Year Ended Dec 31, 2008
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market
Balance – beginning of period	**$ 2,119**	$ (1,474)
Net cost of outstanding put options	**142**	297
Net change in fair value of outstanding derivative financial instruments attributable to:		
- Risk management activities	**(1,409)**	3,090
- Interest expense	**(22)**	60
- Foreign exchange	**(118)**	449
- Other comprehensive income	**(63)**	18
- Settlement of interest rate swaps and other	**4**	(20)
	653	2,420
Put premium financing obligations [(1)]	**(144)**	(301)
Balance – end of period	**509**	2,119
Less: current portion	**479**	1,851
	$ 30	$ 268

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

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

	Three Months Ended		Six Months Ended	
	Jun 30 2009	Jun 30 2008	**Jun 30 2009**	Jun 30 2008
Net realized risk management (gain) loss	**$ (290)**	$ 954	**$ (931)**	$ 1,370
Net unrealized risk management loss	**946**	1,415	**1,409**	1,523
	$ 656	$ 2,369	**$ 478**	$ 2,893

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

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 June 30, 2009, the Company had the following net derivative financial instruments outstanding to manage its commodity price exposures:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Jul 2009	–	Dec 2009	25,000 bbl/d	US$70.00	–	US$111.56	WTI
	Jan 2010	–	Dec 2010	50,000 bbl/d	US$60.00	–	US$75.08	WTI
Crude oil puts	Jul 2009	–	Dec 2009	92,000 bbl/d			US$100.00	WTI

At June 30, 2009, the net cost of outstanding put options and their respective periods of settlement was as follows:

	Q3 2009	Q4 2009
Cost ($ millions)	US$61	US$61

	Remaining term			Volume	Weighted average price			Index
Natural gas								
Natural gas price collars	Jan 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 June 30, 2009.

In addition to the derivative financial instruments noted above, the Company entered into natural gas physical sales contracts for 400,000 GJ/d at an average fixed price of C$5.29 per GJ at AECO for the period July to December 2009.

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 June 30, 2009, the Company had the following interest rate swap contracts outstanding:

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Jul 2009	–	Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%
Swaps – floating to fixed	Jul 2009	–	Feb 2011	C$300	1.0680%	3 month CDOR (2)
	Jul 2009	–	Feb 2012	C$200	1.4475%	3 month CDOR (2)

(1) London Interbank Offered Rate

(2) Canadian Dealer Offered Rate

All interest rate related derivative financial instruments designated as hedges at June 30, 2009 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 June 30, 2009, 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	Jul 2009	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jul 2009	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jul 2009	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at June 30, 2009 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, the Company periodically utilizes foreign currency forward contracts to manage certain foreign currency cash management needs. At June 30, 2009, the Company had US$1,436 million of these contracts outstanding, with terms of approximately 30 days or less.

Financial instrument sensitivities

As required by Canadian GAAP, the Company must provide certain quantitative sensitivities related to its financial instruments, which are prepared on a different basis than those sensitivities currently disclosed in the Company's other continuous disclosure documents. 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 June 30, 2009 resulting from changes in the specified variable, with all other variables held constant. These sensitivities are limited to the impact of changes in a specified variable applied to financial instruments only 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	$ (26)	$ -
Decrease WTI US$1.00/bbl	$ 26	$ -
Increase AECO C$0.10/mcf	$ (4)	$ -
Decrease AECO C$0.10/mcf	$ 4	$ -
Interest rate risk		
Increase interest rate 1%	$ (16)	$ (5)
Decrease interest rate 1%	$ 16	$ 6
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (33)	$ -
Decrease exchange rate by US$0.01	$ 33	$ -

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 June 30, 2009, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At June 30, 2009, the Company had net risk management assets of $536 million with specific counterparties related to derivative financial instruments (December 31, 2008 – $2,119 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	$ 327	$ -	$ -	$ -
Accrued liabilities	$ 1,727	$ -	$ -	$ -
Other long-term liabilities	$ 87	$ 9	$ -	$ -
Long-term debt [(1)]	$ 1,369	$ 400	$ 1,737	$ 6,387

(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 $2,125 million of revolving bank credit facilities due to the extendable nature of the facilities.

12. COMMITMENTS

As at June 30, 2009, the Company had committed to certain payments as follows:

	Remaining 2009	2010	2011	2012	2013	Thereafter
Product transportation and pipeline	$ 115	$ 188	$ 158	$ 134	$ 123	$ 1,165
Offshore equipment operating leases	$ 101	$ 138	$ 137	$ 111	$ 111	$ 378
Offshore drilling	$ 82	$ 59	$ -	$ -	$ -	$ -
Asset retirement obligations [(1)]	$ 9	$ 10	$ 16	$ 17	$ 26	$ 5,799
Office leases	$ 12	$ 29	$ 23	$ 2	$ 2	$ 2
Other	$ 180	$ 185	$ 16	$ 9	$ 7	$ 19

(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 2009 – 2013 represent the minimum required expenditures 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				North Sea				Offshore West Africa				Total Conventional			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
Segmented revenue	**2,000**	4,282	**3,847**	7,497	**271**	537	**446**	1,045	**182**	287	**383**	524	**2,453**	5,106	**4,676**	9,066
Less: royalties	**(192)**	(651)	**(385)**	(1,056)	**(1)**	(1)	**(1)**	(2)	**(16)**	(36)	**(30)**	(79)	**(209)**	(688)	**(416)**	(1,137)
Segmented revenue, net of royalties	**1,808**	3,631	**3,462**	6,441	**270**	536	**445**	1,043	**166**	251	**353**	445	**2,244**	4,418	**4,260**	7,929
Segmented expenses																
Production	**445**	475	**921**	926	**113**	105	**183**	217	**30**	25	**73**	46	**588**	605	**1,177**	1,189
Transportation and blending	**304**	698	**630**	1,191	**2**	2	**5**	5	**-**	-	**-**	-	**306**	700	**635**	1,196
Depletion, depreciation and amortization	**514**	562	**1,061**	1,128	**79**	72	**143**	158	**38**	34	**88**	68	**631**	668	**1,292**	1,354
Asset retirement obligation accretion	**11**	9	**20**	20	**6**	7	**13**	13	**1**	1	**2**	1	**18**	17	**35**	34
Realized risk management activities	**(188)**	954	**(672)**	1,371	**(102)**	-	**(259)**	(1)	**-**	-	**-**	-	**(290)**	954	**(931)**	1,370
Total segmented expenses	**1,086**	2,698	**1,960**	4,636	**98**	186	**85**	392	**69**	60	**163**	115	**1,253**	2,944	**2,208**	5,143
Segmented earnings before the following	**722**	933	**1,502**	1,805	**172**	350	**360**	651	**97**	191	**190**	330	**991**	1,474	**2,052**	2,786
Non-segmented expenses																
Administration																
Stock-based compensation expense																
Interest, net																
Unrealized risk management activities																
Foreign exchange (gain) loss																
Total non-segmented expenses																
Earnings (loss) before taxes																
Taxes other than income tax																
Current income tax expense																
Future income tax recovery																
Net earnings (loss)																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter-segment elimination and other				Total			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
Segmented revenue	**292**	-	**292**	-	**17**	20	**36**	40	**(12)**	(14)	**(68)**	(27)	**2,750**	5,112	**4,936**	9,079
Less: royalties	**(3)**	-	**(3)**	-	**-**	-	**-**	-	**-**	-	**8**	-	**(212)**	(688)	**(411)**	(1,137)
Segmented revenue, net of royalties	**289**	-	**289**	-	**17**	20	**36**	40	**(12)**	(14)	**(60)**	(27)	**2,538**	4,424	**4,525**	7,942
Segmented expenses																
Production	**182**	-	**182**	-	**5**	8	**10**	13	**(2)**	(3)	**(14)**	(5)	**773**	610	**1,355**	1,197
Transportation and blending	**14**	-	**14**	-	**-**	-	**-**	-	**(11)**	(11)	**(23)**	(22)	**309**	689	**626**	1,174
Depletion, depreciation and amortization	**36**	-	**38**	-	**2**	2	**4**	4	**(5)**	-	**(24)**	-	**664**	670	**1,310**	1,358
Asset retirement obligation accretion	**6**	-	**8**	-	**-**	-	**-**	-	**-**	-	**-**	-	**24**	17	**43**	34
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**(290)**	954	**(931)**	1,370
Total segmented expenses	**238**	-	**242**	-	**7**	10	**14**	17	**(18)**	(14)	**(61)**	(27)	**1,480**	2,940	**2,403**	5,133
Segmented earnings before the following	**51**	-	**47**	-	**10**	10	**22**	23	**6**	-	**1**	-	**1,058**	1,484	**2,122**	2,809
Non-segmented expenses																
Administration													**47**	45	**94**	88
Stock-based compensation expense													**92**	459	**96**	459
Interest, net													**124**	31	**181**	80
Unrealized risk management activities													**946**	1,415	**1,409**	1,523
Foreign exchange (gain) loss													**(246)**	(31)	**(123)**	83
Total non-segmented expenses													**963**	1,919	**1,657**	2,233
Earnings (loss) before taxes													**95**	(435)	**465**	576
Taxes other than income tax													**47**	62	**51**	111
Current income tax expense													**87**	151	**204**	306
Future income tax recovery													**(201)**	(301)	**(257)**	(221)
Net earnings (loss)													**162**	(347)	**467**	380

Net additions to property, plant and equipment

	Six Months Ended					
	Jun 30, 2009			Jun 30, 2008		
	Net Expenditures	**Non Cash/Fair Value Changes (1)**	**Capitalized Costs**	Net Expenditures	Non Cash/Fair Value Changes (1)	Capitalized Costs
North America	**$ 869**	**$ (4)**	**$ 865**	$ 1,280	$ 12	$ 1,292
North Sea	**82**	**-**	**82**	124	-	124
Offshore West Africa	**356**	**50**	**406**	258	(2)	256
Other	**-**	**-**	**-**	1	-	1
Oil Sands Mining and Upgrading (2)	**391**	**275**	**666**	2,193	-	2,193
Midstream	**5**	**-**	**5**	4	-	4
Head office	**7**	**-**	**7**	7	-	7
	$ 1,710	**$ 321**	**$ 2,031**	$ 3,867	$ 10	$ 3,877

(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 the Oil Sands Mining and Upgrading assets also include capitalized interest, stock-based compensation, and the impact of intersegment eliminations.

	Property, plant and equipment		Total assets	
	Jun 30 2009	Dec 31 2008	**Jun 30 2009**	Dec 31 2008
Segmented assets				
North America	**$ 21,963**	$ 22,151	**$ 23,450**	$ 24,875
North Sea	**1,878**	2,048	**2,138**	2,638
Offshore West Africa	**2,099**	1,894	**2,167**	2,013
Other	**26**	26	**69**	64
Oil Sands Mining and Upgrading	**13,192**	12,573	**13,581**	12,677
Midstream	**207**	206	**292**	315
Head office	**65**	68	**65**	68
	$ 39,430	$ 38,966	**$ 41,762**	$ 42,650

Capitalized interest

The Company capitalizes construction period interest to Oil Sands Mining and Upgrading 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 six months ended June 30, 2009, pre-tax interest of $92 million was capitalized to Oil Sands Mining and Upgrading (June 30, 2008 - $221 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 September 2007. 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 June 30, 2009:	
Interest coverage (times)	
Net earnings [1]	12.5x
Cash flow from operations [2]	11.9x

(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 Thursday, August 6, 2009. The North American conference call number is 1-866-226-1793 and the outside North American conference call number is 001-416-641-6128. 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, Thursday, August 13, 2009. 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 8634752.

WEBCAST

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

2009 THIRD QUARTER RESULTS

The 2009 third quarter results are scheduled for release prior to market opening on Thursday, November 5, 2009.

For further information, please contact:

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