Canadian Natural

diverse asset base | disciplined growth | strong leadership

FIRST QUARTER REPORT
Three months ended March 31, 2008

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2008 FIRST QUARTER RESULTS

Commenting on first quarter 2008 results, Canadian Natural's Chairman, Allan Markin stated, "It has been a good start to the year for Canadian Natural. We completed our winter drilling program in advance of spring break-up, meeting our targets. Our teams were presented with several weeks of cold weather, leading to many weather related issues. The teams rose to the challenge and delivered impressive results. At the Horizon Project, severe weather conditions factored into lower productivity. As the weather became warmer, efficiencies improved and first oil remains targeted for the third quarter of this year."

John Langille, Vice-Chairman, stated, "First quarter cash flow was a reflection of higher realized crude oil pricing, resulting from a lower heavy crude oil differential. The heavy crude oil differential improved due to reduced refinery cracking margins that influence demand for heavy crude oil. Stronger natural gas pricing also added to the bottom line as a cold, late winter resulted in a draw on natural gas inventories. Natural gas pricing was also affected by fewer liquefied natural gas imports to North America and reduced production coming out of Canada. As a result of the increases in both crude oil and natural gas realized strip prices, our cash flow for the year is projected to be in balance with our capital program. Our balance sheet should continue to strengthen as we expect solid earnings throughout 2008."

Steve Laut, President and Chief Operating Officer of Canadian Natural commented, "During Q1/08, we saw the continued benefits of our high-graded natural gas drilling program with strong and steady production delivering on budget. Our North American crude oil drilling program also produced excellent results, particularly from our Pelican Lake assets. Looking ahead, work at the Primrose East Thermal Project continues on schedule, with production expected for early 2009, a further step towards unlocking the significant value of Canadian Natural's thermal crude oil resource base. Our International crude oil projects are also making significant strides with the Olowi Project in Offshore Gabon continuing on track for first oil targeted for late 2008, along with the mobilization of the deep water drilling rig for Baobab in Offshore Côte d'Ivoire. The Horizon Project remains targeted for a Q3/08 start up with operations readiness on schedule to date. The year of execution has started off extremely well."

HIGHLIGHTS

($ millions, except as noted)	Three Months Ended Mar 31 2008	Dec 31 2007	Mar 31 2007
Net earnings	**$ 727**	$ 798	$ 269
Per common share, basic and diluted	**$ 1.35**	$ 1.48	$ 0.50
Adjusted net earnings from operations (1)	**$ 872**	$ 546	$ 621
Per common share, basic and diluted	**$ 1.61**	$ 1.02	$ 1.15
Cash flow from operations (2)	**$ 1,725**	$ 1,486	$ 1,622
Per common share, basic and diluted	**$ 3.19**	$ 2.75	$ 3.01
Capital expenditures, net of dispositions	**$ 1,753**	$ 1,514	$ 2,009
Daily production, before royalties			
Natural gas (mmcf/d)	**1,538**	1,589	1,717
Crude oil and NGLs (bbl/d)	**327,217**	337,240	327,001
Equivalent production (boe/d)	**583,488**	601,908	613,114

(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.

- Natural gas production volumes for the first quarter represented 44% of the Company's total production. Natural gas production for Q1/08 averaged 1,538 mmcf/d, down 10% from 1,717 mmcf/d for Q1/07 and down 3% from 1,589 mmcf/d for Q4/07. As expected, volumes in Q1/08 reflected a strong winter drilling program offset by the natural decline in base production and continued reallocation of capital towards higher return projects in crude oil.
- Total crude oil and NGLs production for Q1/08 was 327,217 bbl/d. Q1/08 production volumes were slightly higher than Q1/07 volumes of 327,001 bbl/d, and decreased 3% from Q4/07 volumes of 337,240 bbl/d. Volumes in Q1/08 reflect the transition between steam and production cycles for Primrose thermal wells and continued conversion of production wells to polymer injection wells at Pelican Lake.
- Quarterly cash flow from operations was $1.73 billion, an increase of 6% from Q1/07 and an increase of 16% from Q4/07. The increase from Q1/07 and Q4/07 primarily reflected higher crude oil and natural gas realizations, partially offset by realized hedging losses.
- Quarterly net earnings for Q1/08 were $727 million. Quarterly adjusted net earnings from operations for Q1/08 were $872 million.
- Maintained a strong undeveloped conventional core land base in Canada of 11.8 million net acres - a key asset for continued value growth.
- Continued production improvements at the Pelican Lake Field were realized from new drilling activity and the expansion of the enhanced crude oil recovery program. Pelican Lake crude oil production averaged approximately 37,000 bbl/d during the first quarter of 2008, up significantly by 5,000 bbl/d from Q1/07 and up 1,000 bbl/d from Q4/07.
- The Primrose East Expansion, which is targeted to add 40,000 bbl/d of capacity, made significant progress and is targeted for first steaming in late 2008 and production in early 2009.
- Secured a deep water drilling rig for the Baobab Field. The equipment was mobilized in early Q2/08, enabling work to begin on the restoration of shut-in production. It is targeted that a minimum 3 of the 5 Baobab wells come on stream over the course of 2008 and 2009.

- The Olowi Project in Offshore Gabon continues on track. The drilling rig has been mobilized and arrived on site in late April. First crude oil production is targeted for Q4/08.
- Work progress on the Horizon Oil Sands Project ("Horizon Project") exited Q1/08 at 94% complete and first oil is targeted for Q3/08.
- Commencing January 1, 2009, the Company's commodity hedging program has been revised by its Board of Directors to allow for the hedging of up to 50% (currently 75%) of the near 12 months budgeted production and up to 25% (currently 50%) of the following 13 to 24 months estimated production. The purchase of put options will continue to be in addition to the above parameters. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects.
- Declared a quarterly cash dividend on common shares of C$0.10 per common share, payable July 1, 2008.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in core regions where it can dominate the land base and infrastructure. Undeveloped land is critical to the Company's ongoing growth and development within these core regions. Land inventories are maintained to enable 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. Further, the Company maintains large project inventories and production diversification among each of the commodities it produces; namely natural gas, light/medium and heavy crude oil and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

OPERATIONS REVIEW

Activity by core region

	Net undeveloped land as at Mar 31, 2008 (thousands of net acres)	Drilling activity three months ended Mar 31, 2008 (net wells) (1)
Canadian conventional		
Northeast British Columbia	**2,348**	**20.2**
Northwest Alberta	**1,451**	**53.3**
Northern Plains	**6,528**	**170.8**
Southern Plains	**920**	**68.3**
Southeast Saskatchewan	**122**	**10.1**
In-situ Oil Sands	**476**	**35.1**
	11,845	**357.8**
Horizon Oil Sands Project	**115**	**-**
United Kingdom North Sea	**268**	**1.6**
Offshore West Africa	**206**	**0.6**
	12,434	**360.0**

(1) Drilling activity includes stratigraphic test and service wells

Drilling activity (number of wells)

	Three Months Ended Mar 31			
	2008		2007	
	Gross	**Net**	Gross	Net
Crude oil	**184**	**173**	210	193
Natural gas	**191**	**161**	246	201
Dry	**13**	**11**	68	60
Subtotal	**388**	**345**	524	454
Stratigraphic test / service wells	**15**	**15**	234	234
Total	**403**	**360**	758	688
Success rate (excluding stratigraphic test / service wells)		**97%**		87%

North America Conventional

North America natural gas

	Quarterly Results		
	Q1/08	Q4/07	Q1/07
Natural gas production (mmcf/d)	**1,513**	1,562	1,694
Net wells targeting natural gas	**167**	92	245
Net successful wells drilled	**161**	80	201
Success rate	**96%**	87%	82%

- Q1/08 North American natural gas production decreased 11% from Q1/07 and decreased 3% from Q4/07, reflecting natural declines in base production and the Company's strategic decision to reduce spending on natural gas drilling. Despite the decrease in production, the Company had a highly successful winter drilling program with all planned wells drilled and all planned tie-ins completed prior to spring break-up.
- Canadian Natural drilled 167 net targeted natural gas wells in Q1/08 with an active program across the Company's core regions. In Northeast British Columbia, 20 net wells were drilled, while in Northwest Alberta, 50 net wells were drilled. In the Northern Plains, 44 net wells were drilled, with 53 net wells drilled in the Southern Plains.
- Planned drilling activity for Q2/08 includes 8 natural gas wells compared to drilling activity for Q2/07 of 6 natural gas wells.

North America crude oil and NGLs

	Quarterly Results		
	Q1/08	Q4/07	Q1/07
Crude oil and NGLs production (bbl/d)	**248,960**	256,843	237,489
Net wells targeting crude oil	**176**	172	207
Net successful wells drilled	**171**	168	191
Success rate	**97%**	98%	92%

- Q1/08 North America crude oil and NGLs production increased 5% from Q1/07 and decreased 3% from Q4/07 levels. The majority of the incremental production volume from Q1/07 was contributed by thermal crude oil and Pelican Lake crude oil. The decrease from Q4/07 is a reflection of transitioning off the production cycle peaks at Primrose North pads.
- The Company has decided to accelerate the drilling of additional Primrose North pads originally scheduled for 2009 requiring additional capital in 2008 of approximately $130 million; approximately 49 additional horizontal wells of the 120 well program will be drilled in 2008 with the remainder drilled in 2009. Steaming of these wells will commence in Q4/09.
- The Primrose East Expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility, is targeted to add approximately 40,000 bbl/d of crude oil. Drilling and construction is on schedule, and production is targeted to commence in early 2009. Primrose East is the second phase of the 300,000 bbl/d conventional expansion plan identified to unlock the value from Canadian Natural's thermal crude oil resource base.
- In early 2007, Canadian Natural announced 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 as part of the Company's normal course of business.

- Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout Q1/08. In Q1/08, the Company drilled 25 horizontal wells with plans to drill an additional 57 horizontal and 7 vertical service wells throughout the remainder of 2008. Pelican Lake production averaged approximately 37,000 bbl/d for Q1/08 compared to approximately 32,000 bbl/d for Q1/07 and approximately 36,000 bbl/d for the prior quarter. The response from the polymer flood project continues to be positive and the Company is moving forward on converting regions currently under waterflood to polymer flood and expanding the polymer flood to new areas.
- Conventional heavy crude oil production volumes decreased slightly in Q1/08 compared to Q4/07, reflecting expected declines in certain older fields and higher than forecast downtime due to cold weather.
- During Q1/08, drilling activity targeted 176 net wells including 96 wells targeting heavy crude oil, 25 wells targeting Pelican Lake crude oil, 22 wells targeting thermal crude oil and 33 wells targeting light crude oil.
- Planned drilling activity for Q2/08 includes 62 net crude oil wells, excluding stratigraphic test and service wells.

International

	Quarterly Results		
	Q1/08	Q4/07	Q1/07
Crude oil production (bbl/d)			
North Sea	**49,568**	52,709	61,869
Offshore West Africa	**28,689**	27,688	27,643
Natural gas production (mmcf/d)			
North Sea	**11**	13	15
Offshore West Africa	**14**	14	8
Net wells targeting crude oil	**2.2**	0.6	2.8
Net successful wells drilled	**2.2**	0.6	2.8
Success rate	**100%**	100%	100%

North Sea

- During Q1/08, 1.6 net wells were drilled and completed with an additional 1.6 net wells drilling at quarter end. Crude oil production was down 6% in Q1/08 to 49,568 bbl/d from 52,709 bbl/d in Q4/07 as a result of the disposal of Canadian Natural's interests in the B-Block Fields in December 2007, higher than anticipated downtime on Banff and further decline in the Lyell subsea wells.
- Focus on waterflood optimization at Ninian continued with 1 well being converted to water injection during Q1/08 and a further well scheduled to be converted to water injection in Q2/08 to increase water injection capacity. Compared to Q1/07, the Company has increased injection by 45%.
- At Murchison, the first of 2 production wells planned for 2008 was completed during Q1/08. The second well is scheduled for completion in Q2/08.
- Following disappointing injection performance from the subsea wells drilled at Columba E in 2007, the Company has successfully increased injection by 60% with the optimization of the current pumps to inject above fracture pressure. As a result, a positive production response is forecast for later in 2008.

Offshore West Africa

- During Q1/08, 0.6 net crude oil wells were drilled and completed. This represented the final well in the West Espoir drilling campaign with the drilling rig being released during the quarter. The project was delivered on budget and on schedule.
- Offshore West Africa's crude oil production was up 4% in Q1/08 to 28,689 bbl/d from 27,688 bbl/d in Q4/07 following the successful completion of drilling at West Espoir and stable production from Baobab.
- Progress on the Facility Upgrade Project at Espoir to increase capacity of the Floating, Production, Storage and Offtake Vessel ("FPSO") is progressing ahead of schedule and is expected to now be complete in Q3/09, an acceleration of 3 to 6 months from the original estimate.
- The deep water drilling rig for Baobab was mobilized early in Q2/08, enabling work to begin on the restoration of shut-in production. It is targeted that a minimum 3 of the 5 shut-in Baobab wells be on stream over the course of 2008 and 2009.
- At the Olowi project in Offshore Gabon, a drilling rig was mobilized and drilling commenced in early May of this year with first crude oil production targeted for late 2008.

Horizon Project

- Canadian Natural achieved an overall 94% completion at the end of Q1/08, with craftspeople actively performing hydrotests, airblows, rotation checks and various pre-commissioning activities. Operations teams are walking down the systems in each plant to ensure they are complete prior to commissioning. The last substation on site has been energized and the Extraction Plant started operating on water in late April.
- Mine Production commenced operations in the first quarter, using Canadian Natural mine operators and equipment to work on the overburden removal. This is the second area of the Horizon Project where operations have begun, with water systems being the first. This represents a significant milestone for the Company with early operations providing training benefits for Canadian Natural operators prior to full start up.
- Commissioning is progressing as 96 plant systems have been turned over and commissioned (out of an estimated 820); along with 10 mine haul trucks (out of 23) and 2 hydraulic shovels, all on schedule. The balance of the mine equipment will be turned over and commissioned to support the ramp up of oil sands mining and bitumen production.
- At the end of the first quarter, capital spending on Phase 1 of the Horizon Project was at 111% of the original budget of $6.8 billion. Looking forward to completion, targeted for Q3/08, anticipated capital spending on Phase 1 construction will be within the previously announced range of 25%-28% above the original budget.
- There has been progress in hiring of operators with 89% of required personnel in place, all maintenance contracts finalized and all supervision mobilized on site. The plants are prepared to start up and 190,000 barrels of diluent for start up have been delivered to the Horizon Project site.
- Once commissioning has been completed and operations have begun, it is anticipated that ramp up to full production will occur over a 3 to 4 month period. The target is to be at 85% design capacity by year end 2008. Full capacity is anticipated to be achieved during Q1/09 as planned.
- The sales pipeline which will transport production from the site to Edmonton is on track for completion in Q2/08. Approximately 750,000 barrels of synthetic crude oil from initial production volumes will be used to fill the pipeline.
- While focus remains on completion and start up of Phase 1, Canadian Natural continues to plan for future expansions. Two coke drums have been received on site along with all components for the two hydrotreating reactors that will be installed as part of the Phase 2/3 expansion.

Horizon Project Status Summary

	December 31, 2007	March 31, 2008			June 30, 2008	
	Actual	Actual	Q1/08 Forecast	Original Plan	Q2/08 Forecast	Original Plan
Phase 1 - Work progress (cumulative)	90%	94%	95%	97%	97%	99%
Phase 1 - Construction capital spending* (cumulative)	99%	111%	110%	97%	122%	100%

**Relative to overall Phase 1 project capital of $6.8 billion*

Accomplished to the end of the First Quarter of 2008

Procurement
- Site assembly of Mine Operations equipment (shovels and heavy haul trucks) is on schedule.
- Fixed Plant Maintenance contractors have mobilized.

Modularization
- All oversized loads for construction have been delivered to site. Ongoing deliveries of mine equipment (trucks and shovels) will continue through the summer.

Construction
- Overall construction progress is 91% complete.
- Mine overburden removal has moved 56.7 million bank cubic meters, which represents approximately 80% of the total to be moved before start up.
- Completed Tar River Diversion and Fish Habitat construction.
- Substantially completed Extraction Plant in the first quarter and have introduced water to the plant in April.
- Completed construction of Tanks 11 and 12 in the East Tank Farm and filled with diluent for start up.
- Installed 3 nitrogen storage tanks and completed construction of the Nitrogen Plant, now ready for operations.
- Installed Auxiliary Boiler in Cogeneration.
- Assumed occupancy of Main Warehouse.
- Substations energized for Sulphur Recovery and Gas Treating, representing the last on-site substations to be energized.
- Substantially completed construction of Amine Plant and moving into Pre-Commissioning.
- Started construction of Sulphur Pipeline.
- Completed piping in Heat Integration.

Systems Commissioned and Turned Over during the Quarter
- Firewater in both tank farms.
- Tanks 11 and 12.
- Electrical Distribution to Heat Integration, Coker/DRU, Tank Farms and Froth Treatment.
- Substations in Sulphur and Gas Treating energized.

Commissioning Schedule

Completed To Date
- Permanent Potable Water Treatment
- Permanent Sewage Treatment
- Natural Gas Pipeline
- Raw and Recycled Water Pipelines
- River Water Intake and Pumphouse
- Raw Water Pond and Pumphouse
- Recycle Water Pond and Pumphouse
- Electrical Distribution System, including all substations
- Tanks 11 and 12 completed for diluent fill
- Main Piperack (air, water, gas, power)
- Instrument and Utility Air System

On Track for Q2 2008

- Extraction
- Flare System
- Cogeneration (steam)
- Cooling and Heating
- Delayed Coker / Diluent Recovery Unit
- Hydrogen Plant
- Gas Treating and Sulphur Recovery
- West Tank Farm (inter plant)
- Sulphur Block Pipelines
- Synthetic Crude Oil (product) Pipeline

On Track for Q3 2008

- Ore Preparation Plant
- Froth Treatment
- Cogeneration (power)
- Pipeline Corridors
- Hydrotreater
- Remainder of East Tank Farm (product)

MARKETING

	Quarterly Results		
	Q1/08	Q4/07	Q1/07
Crude oil and NGLs pricing			
WTI[1] benchmark price (US$/bbl)	**$ 97.96**	$ 90.63	$ 58.23
Western Canadian Select blend differential[2] from WTI (%)	**22%**	37%	27%
Corporate average pricing before risk management (C$/bbl)	**$ 78.99**	$ 58.03	$ 51.71
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 6.76**	$ 5.69	$ 7.07
Corporate average pricing before risk management (C$/mcf)	**$ 7.77**	$ 6.28	$ 7.74

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

(2) Beginning in Q1 2008, the Company has quantified the Heavy Differential using the Western Canadian Select ("WCS") blend as the heavy crude oil marker. Prior period amounts have been reclassified.

- In Q1/08, the Western Canadian Select heavy crude oil differential as a percent of WTI was 22%, compared to 37% in Q4/07. Heavy crude oil differentials improved in Q1/08 due to the narrowing of cracking spreads at refineries and a tight supply demand balance in PADD II. The lower cracking spread resulted in higher demand for heavy crude oil leading to improved differentials. Total Western Canadian production was down slightly in the first quarter which also contributed to improved differentials.
- The Company continues its efforts with other industry players in finding new markets and easing the logistical constraints in getting Western Canadian heavy crude oil to new markets, such as the US Gulf Coast. Canadian heavy crude oil is very competitive against other international grades available in the US Gulf Coast. For Q1/08, the differential for the heavy crude oil marker, Mayan grade, was US$16.79/bbl or 17%.
- During Q1/08, the Company contributed approximately 153,000 bbl/d of its heavy crude oil streams to the Western Canadian Select blend as market conditions resulted in this strategy offering the optimal pricing for bitumen.
- Demand for natural gas increased more than expected for Q1/08 leading to increased natural gas pricing. The quarter saw fewer imports of liquefied natural gas to North America as a result of stronger pricing in Europe and Asia, resulting in decreased supply to the United States and Canada. A cold winter also contributed to increased demand during the quarter along with renewed consumption from the industrial sector.

FINANCIAL REVIEW

- Canadian Natural has structured its financial position to profitably grow its conventional crude oil and natural gas operations over the next several years and to build the financial capacity to complete the Horizon Project and other major projects. A brief summary of the Company's strengths are:
  - A diverse asset base geographically and by product - produced in excess of 583,000 boe/d in Q1/08, comprised of approximately 44% natural gas and 56% crude oil - with 95% of production located in G8 countries with stable and secure economies.
  - Financial stability and liquidity - cash flow from operations of $1.7 billion for Q1/08, available unused bank lines of $2.6 billion at March 31, 2008 and access to capital debt markets supported by strong credit ratings.
  - 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 throughout the Horizon Project.
  - A strengthening balance sheet with debt to book capitalization of 44% and debt to EBITDA of 1.6 times, both within targeted ranges.
- In January 2008, the Company issued US$1,200 million of unsecured notes comprised of US$400 million of 5.15% unsecured notes due February 2013, US$400 million of 5.90% unsecured notes due February 2018, and US$400 million of 6.75% unsecured notes due February 2039. Proceeds from the securities issues were used to repay bankers' acceptances under the Company's bank credit facilities.
- Commencing January 1, 2009, the Company's commodity hedging program has been revised by its Board of Directors to allow for the hedging of up to 50% of the near 12 months budgeted production and up to 25% of the following 13 to 24 months estimated production. The purchase of put options will continue to be in addition to the above parameters. The current program allows for hedging of 75% of the near 12 months budget and production, up to 50% of the following 13 to 24 months estimated production, and up to 25% of the expected production in months 25 to 48. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects.
- In 2007 and 2008, the Province of Alberta issued certain details of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. The Company is currently awaiting finalization and government approval of the royalty regulations, however it expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty changes and that its level of activity in Alberta in aggregate will be reduced from what it otherwise would have been in the absence of such royalty changes.
- Declared a quarterly cash dividend on common shares of C$0.10 per common share, payable July 1, 2008.

OUTLOOK

The Company forecasts 2008 production levels before royalties to average between 1,429 and 1,513 mmcf/d of natural gas and between 316,000 and 366,000 bbl/d of crude oil and NGLs. Q2/08 production guidance before royalties is forecast to average between 1,479 and 1,513 mmcf/d of natural gas and between 306,000 and 323,000 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 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 2008 guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitutes forward-looking statements. 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.

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 assurance that the plans, initiatives or expectations upon which they are based will occur.

The forward-looking statements are based on current expectations, estimates and projections about Canadian Natural Resources Limited (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, uncertainties and other factors 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 factors 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 its 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 at times 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 interdependent 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 important factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management's estimates or opinions change.

Management's Discussion and Analysis

Management's Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2008 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2007.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("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 and cash flow from operations. 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 measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings in the "Financial Highlights" 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 are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices exclude the effect of risk management activities and transportation and blending costs, except where noted otherwise. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion refers primarily to the Company's financial results for the three months ended March 31, 2008 in relation to the comparable period in 2007 and the fourth quarter of 2007. The accompanying tables form an integral part of this MD&A. This MD&A is dated May 8, 2008. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2007, is available on SEDAR at www.sedar.com.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
Revenue, before royalties	**$ 3,967**	$ 3,200	$ 3,118
Net earnings	**$ 727**	$ 798	$ 269
Per common share – basic and diluted	**$ 1.35**	$ 1.48	$ 0.50
Adjusted net earnings from operations [1]	**$ 872**	$ 546	$ 621
Per common share – basic and diluted	**$ 1.61**	$ 1.02	$ 1.15
Cash flow from operations [2]	**$ 1,725**	$ 1,486	$ 1,622
Per common share – basic and diluted	**$ 3.19**	$ 2.75	$ 3.01
Capital expenditures, net of dispositions	**$ 1,753**	$ 1,514	$ 2,009

(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" 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" below lists certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

	Three Months Ended		
($ millions)	***Mar 31 2008***	*Dec 31 2007*	*Mar 31 2007*
Net earnings as reported	***$ 727***	*$ 798*	*$ 269*
Stock-based compensation expense (recovery), net of tax [a]	***-***	*(11)*	*17*
Unrealized risk management loss, net of tax [b]	***76***	*593*	*362*
Unrealized foreign exchange loss (gain), net of tax [c]	***110***	*(41)*	*(27)*
Effect of statutory tax rate and other legislative changes on future income tax liabilities [d]	***(41)***	*(793)*	*-*
Adjusted net earnings from operations	***$ 872***	*$ 546*	*$ 621*

(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 as part of the Horizon Oil Sands Project during the construction period.

(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in fair value of non-designated hedges flowing through 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 immediately recognized in net earnings.

(d) All substantively 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. 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. Income tax rate and other legislative changes in the fourth quarter of 2007 resulted in a reduction of future income tax liabilities of approximately $793 million in North America.

Cash Flow from Operations

	Three Months Ended		
($ millions)	***Mar 31 2008***	*Dec 31 2007*	*Mar 31 2007*
Net earnings	***$ 727***	*$ 798*	*$ 269*
Non-cash items:			
Depletion, depreciation and amortization	***688***	*719*	*709*
Asset retirement obligation accretion	***17***	*17*	*18*
Stock-based compensation expense (recovery)	***-***	*(16)*	*25*
Unrealized risk management loss	***108***	*845*	*536*
Unrealized foreign exchange loss (gain)	***126***	*(47)*	*(32)*
Deferred petroleum revenue tax (recovery) expense	***(21)***	*17*	*(3)*
Future income tax expense (recovery)	***80***	*(847)*	*100*
Cash flow from operations	***$ 1,725***	*$ 1,486*	*$ 1,622*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the first quarter of 2008 were $727 million compared to $269 million for the first quarter of 2007 and $798 million for the prior quarter. Net earnings for the first quarter of 2008 included net unrealized after-tax expenses of $145 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 $352 million for the first quarter of 2007 and net unrealized after-tax income of $252 million for the prior quarter. Excluding these items, adjusted net earnings from operations for the first quarter of 2008 increased to $872 million compared to $621 million for the first quarter of 2007 and $546 million for the prior quarter. The increase in adjusted net earnings from the first quarter of 2007 was primarily due to the impact of higher realized pricing, lower depletion, depreciation and amortization expense, lower interest expense, and lower administration expense. These factors were partially offset by higher realized risk management losses, higher royalty and production expense, lower sales volumes and the impact of the stronger Canadian dollar relative to the US dollar. The increase from the prior quarter was primarily due to the impact of higher realized pricing, lower depletion, depreciation and amortization expense, and the impact of the weaker Canadian dollar relative to the US dollar, partially offset by higher realized risk management losses, higher royalty and production expense, and lower sales volumes.

The Company expects that consolidated net earnings will continue to reflect significant quarterly volatility due to the impact of risk management activities, stock-based compensation expense and fluctuations in foreign exchange rates.

The Company’s commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company’s cash flow for its capital expenditures throughout the Horizon Oil Sands Project (“Horizon Project”) construction period. This program currently allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of put options is in addition to the above parameters. In accordance with the policy, approximately 61% of budgeted crude oil volumes are hedged for the remainder of 2008, approximately 18% of budgeted natural gas volumes are hedged for the second and third quarters of 2008 and approximately 6% of estimated crude oil volumes are hedged for 2009. In addition, 50,000 bbl/d of crude oil volumes are protected by put options for the remainder of 2008 at a strike price of US$55.00 per barrel and 50,000 bbl/d of crude oil volumes are protected by put options for 2009 at a strike price of US$80.00 per barrel.

Commencing January 1, 2009, following the planned completion of Phase 1 of the Horizon Project, the Company’s commodity hedging program has been revised by its Board of Directors to allow for the hedging of up to 50% of the near 12 months budgeted production and up to 25% of the following 13 to 24 months estimated production. The purchase of put options will continue to be in addition to the above parameters.

The Company’s outstanding commodity related financial derivatives as at March 31, 2008 are detailed in the “Liquidity and Capital Resources” section of this MD&A.

The commodity derivative financial instruments currently outstanding have not been designated as hedges for accounting purposes (the “non-designated hedges”). The fair value of these non-designated hedges is based on prevailing forward commodity prices in effect at the end of each reporting period and is reflected in risk management activities in consolidated net earnings. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at March 31, 2008.

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 $108 million ($76 million after-tax) on its commodity risk management activities for the three months ended March 31, 2008. Mark-to-market unrealized gains and losses do not impact the Company’s current cash flow or its ability to finance ongoing capital programs. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects. For further details, refer to the “Risk Management Activities” section of this MD&A.

For the first quarter of 2008, no stock-based compensation expense was recognized as the expense associated with options vesting in the normal course was offset by the impact of the lower share price at March 31, 2008 (Company’s share price as at: March 31, 2008 - C$70.27; December 31, 2007 - C$72.58; March 30, 2007 - C$63.75; December 31, 2006 - C$62.15). As required by GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period based on the difference between the exercise price of the stock options and the market price of the Company’s common shares, pursuant to a graded vesting schedule. The liability is revalued quarterly to reflect the changes in the market price of the Company’s common shares and the options exercised or surrendered in the period, with the net change recognized in net earnings, or capitalized as part of the Horizon Project during the construction period. The stock-based compensation liability at March 31, 2008 reflected the Company’s potential cash liability should all the vested options be surrendered for a cash payout at the market price on March 31, 2008. In periods when substantial share price changes occur, the Company’s net earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

Cash flow from operations for the first quarter of 2008 increased to $1,725 million compared to $1,622 million for the first quarter of 2007 and $1,486 million for the prior quarter. The increase from the first quarter of 2007 was primarily due to the impact of higher realized pricing, partially offset by higher realized risk management losses, higher royalty and production expense, higher current income tax expense, lower sales volumes and the impact of the stronger Canadian dollar relative to the US dollar. The increase from the prior quarter was primarily due to the impact of higher realized pricing and the impact of the weaker Canadian dollar relative to the US dollar, partially offset by higher realized risk management losses, higher royalty and production expense and higher current income tax expense.

Total production before royalties for the first quarter of 2008 decreased 5% to 583,488 boe/d from 613,114 boe/d for the first quarter of 2007 and 3% from 601,908 boe/d for the prior quarter.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)		**Mar 31 2008**		Dec 31 2007		Sep 30 2007		Jun 30 2007
Revenue, before royalties	**$**	**3,967**	$	3,200	$	3,073	$	3,152
Net earnings	**$**	**727**	$	798	$	700	$	841
Net earnings per common share								
– Basic and diluted	**$**	**1.35**	$	1.48	$	1.30	$	1.56

($ millions, except per common share amounts)		Mar 31 2007		Dec 31 2006		Sep 30 2006		Jun 30 2006
Revenue, before royalties	$	3,118	$	2,826	$	3,108	$	3,041
Net earnings	$	269	$	313	$	1,116	$	1,038
Net earnings per common share								
– Basic and diluted	$	0.50	$	0.58	$	2.08	$	1.93

Net earnings over the eight most recently completed quarters generally reflected fluctuations in realized crude oil and natural gas prices, fluctuations in sales volumes, the impact of mark-to-market accounting of financial instruments, fluctuations in depletion, depreciation and amortization charges, fluctuations in foreign exchange rates, and adjustments to future income tax liabilities due to statutory tax rate and other legislative changes. More specifically, volatility in quarterly net earnings was primarily due to:

- Crude oil pricing

  Crude oil prices reflected demand growth, continued geopolitical uncertainties and fluctuations in the Heavy Crude Oil Differential from WTI ("Heavy Differential") in North America.

- Natural gas pricing

  Natural gas prices primarily reflected seasonal fluctuations in both the demand for natural gas and inventory storage levels and fluctuations in liquefied natural gas imports into the US.

- Crude oil and NGLs sales volumes

  Crude oil and NGLs sales volumes primarily reflected increased production from the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, development of West and East Espoir, and additional sales volumes from the Anadarko Canada Corporation ("ACC") acquisition completed in the fourth quarter of 2006. Crude oil and NGLs sales volumes also reflected fluctuations in production from the North Sea due to timing of maintenance activities and liftings and the impact of shut-in Baobab production in Offshore West Africa.

- Natural gas sales volumes

  Natural gas sales volumes primarily reflected additional natural gas volumes as a result of the ACC acquisition and internally generated growth. The increases were partially offset by production declines due to the Company's strategic reduction in natural gas drilling activity.

- Foreign exchange rates

  A general strengthening of the Canadian dollar relative to the US dollar has decreased 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 balances 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 swaps.

- Risk management

  Net earnings have fluctuated due to the recognition of realized and unrealized gains and losses from the mark-to-market of the Company's risk management activities.

- Changes in income tax expense

  Income tax expense (recovery) fluctuations include statutory tax rate and other legislative changes enacted or substantively enacted in the various periods.

- Stock-based compensation

  Net earnings have fluctuated 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.

- Production expense

  Production expense has fluctuated company wide primarily due to the impact for the demand for services, the industry-wide inflationary cost pressures experienced in prior years in all segments and the impact of seasonal costs that are dependent on weather and the fluctuations in product mix.

- Depletion, depreciation and amortization

  Depletion, depreciation and amortization expense has fluctuated due to changes in sales volumes, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, and a higher depletion base in North America related to the ACC acquisition.

OPERATING HIGHLIGHTS

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
Crude oil and NGLs ($/bbl) [1]			
Sales price [2]	**$ 78.99**	$ 58.03	$ 51.71
Royalties	**8.70**	6.66	4.92
Production expense	**14.81**	11.53	13.81
Netback	**$ 55.48**	$ 39.84	$ 32.98
Natural gas ($/mcf) [1]			
Sales price [2]	**$ 7.77**	$ 6.28	$ 7.74
Royalties	**1.35**	0.94	1.48
Production expense	**1.03**	0.91	0.97
Netback	**$ 5.39**	$ 4.43	$ 5.29
Barrels of oil equivalent ($/boe) [1]			
Sales price [2]	**$ 65.09**	$ 49.23	$ 49.32
Royalties	**8.43**	6.21	6.76
Production expense	**11.02**	8.85	10.10
Netback	**$ 45.64**	$ 34.17	$ 32.46

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

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

BUSINESS ENVIRONMENT

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
WTI benchmark price (US$/bbl)	**$ 97.96**	$ 90.63	$ 58.23
Dated Brent benchmark price (US$/bbl)	**$ 96.94**	$ 88.65	$ 57.76
WCS blend differential from WTI (US$/bbl) (1)	**$ 21.41**	$ 33.74	$ 15.48
WCS blend differential from WTI (%) (1)	**22%**	37%	27%
Condensate benchmark price (US$/bbl)	**$ 98.40**	$ 90.89	$ 58.78
NYMEX benchmark price (US$/mmbtu)	**$ 8.07**	$ 7.03	$ 6.96
AECO benchmark price (C$/GJ)	**$ 6.76**	$ 5.69	$ 7.07
US / Canadian dollar average exchange rate	**$ 0.9958**	$ 1.0193	$ 0.8535

(1) Beginning in Q1 2008, the Company has quantified the Heavy Differential using the Western Canadian Select ("WCS") blend as the heavy crude oil marker. Prior period amounts have been reclassified.

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$97.96 per bbl for the first quarter of 2008, an increase of 68% from US$58.23 per bbl for the first quarter of 2007, and an increase of 8% from US$90.63 for the prior quarter. WTI pricing during the first quarter of 2008 generally reflected continued strong demand for crude oil and continued geopolitical events resulting in increased market uncertainty.

Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Dated Brent ("Brent") pricing, which generally continued to benefit from strong European and Asian demand. Brent averaged US$96.94 per bbl for the first quarter of 2008, an increase of 68% compared to US$57.76 per bbl for the first quarter of 2007, and an increase of 9% from US$88.65 per bbl for the prior quarter.

The Company's realized crude oil prices increased from the first quarter of 2007 and the prior quarter primarily as a result of increased WTI and Brent pricing and a narrower Heavy Differential, offset by the impact of a strong Canadian dollar. The Heavy Differential averaged 22% for the first quarter of 2008 compared to 27% for the first quarter of 2007, and 37% for the prior quarter. The narrowing of the Heavy Differential from the prior period was primarily due to reduced Canadian production of heavy crude oil and reduced refinery cracking margins. Realized prices continued to be adversely impacted by the strong Canadian dollar.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of geopolitical events and potential refinery outages. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery cracking margins.

NYMEX natural gas prices averaged US$8.07 per mmbtu for the first quarter of 2008, an increase of 16% from US$6.96 per mmbtu for the first quarter of 2007, and an increase of 15% from US$7.03 per mmbtu for the prior quarter. AECO natural gas prices for the first quarter of 2008 decreased 4% from $7.07 per GJ in the first quarter of 2007 to average $6.76 per GJ, and increased 19% from $5.69 per GJ for the prior quarter. Fluctuations in natural gas prices from the comparable periods were primarily related to higher overall demand and lower storage levels, resulting from the colder weather experienced late in the first quarter of 2008, and lower liquefied natural gas imports into the US during the first quarter of 2008.

Operating, Royalty and Capital Costs

Strong commodity prices in recent years have resulted in increased demand and costs for oilfield services worldwide. This has lead to inflationary operating and capital cost pressures throughout the North America crude oil and natural gas industry, particularly related to drilling activities and oil sands developments. The strong commodity price environment has also impacted costs in international basins, due in large part to the high demand for offshore drilling rigs.

The crude oil and natural gas industry is also experiencing cost pressures related to environmental regulations, both in North America and internationally. In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in 2010 to address industrial greenhouse gas ("GHG") emissions. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants. In Alberta, GHG regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour gas plant, are captured under the regulations. In the UK, GHG regulations have been in effect since 2005. During Phase 1 (2005-2007) of the UK National Allocation Plan the Company operated below its CO_2 allocation. For Phase 2 (2008-2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with any requirement now in effect.

During the first quarter of 2008, British Columbia announced a carbon tax on fuel consumed in the province. Commencing July 1, 2008, the carbon tax will be assessed at $10/tonne of CO_2e, increasing to $30/tonne by July 1, 2012.

Continued cost pressures and the final outcome of changes to environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects.

In 2007 and 2008, the Province of Alberta issued certain details of its proposed changes to the Alberta crude oil and natural gas royalty regime, effective January 1, 2009. These proposed changes 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; and
- New royalty formulas for conventional crude oil and natural gas that are to operate on sliding scales ranging up to 50% determined by commodity prices and well productivity.

The Company is currently awaiting finalization and government approval of the royalty regulations, however it expects that its 2009 and future Alberta royalty payments will increase as a result of the proposed royalty changes and that its level of activity in Alberta in aggregate will be reduced from what it otherwise would have been in the absence of such royalty changes.

PRODUCT PRICES

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 72.86**	$ 50.49	$ 46.09
North Sea	**$ 99.01**	$ 83.44	$ 68.83
Offshore West Africa	**$ 96.31**	$ 81.89	$ 58.60
Company average	**$ 78.99**	$ 58.03	$ 51.71
Natural gas ($/mcf) (1) (2)			
North America	**$ 7.80**	$ 6.31	$ 7.79
North Sea	**$ 3.30**	$ 3.62	$ 4.49
Offshore West Africa	**$ 7.89**	$ 5.49	$ 5.97
Company average	**$ 7.77**	$ 6.28	$ 7.74
Company average ($/boe) (1) (2)	**$ 65.09**	$ 49.23	$ 49.32
Percentage of gross revenue (2) (excluding midstream revenue)			
Crude oil and NGLs	**68%**	66%	56%
Natural gas	**32%**	34%	44%

(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.

The Company's realized crude oil prices increased 53% to average $78.99 per bbl for the first quarter of 2008 from $51.71 per bbl for the first quarter of 2007, and increased 36% from $58.03 per bbl for the prior quarter. The Company's realized crude oil prices increased from the first quarter of 2007 and the prior quarter primarily as a result of an increased WTI and Brent benchmark prices and a narrower Heavy Differential, partially offset by a strong Canadian dollar relative to the US dollar.

The Company's realized natural gas price increased marginally to average $7.77 per mcf for the first quarter of 2008 from $7.74 per mcf for the first quarter of 2007, and increased 24% from $6.28 per mcf for the prior quarter. The increase in realized natural gas prices from the prior quarter primarily reflected colder winter temperatures during the later part of the first quarter of 2008 and the impact of an overall reduction by the industry for natural gas drilling in response to industry wide inflationary pressures. The reduced drilling activity and production volumes and lower liquefied natural gas imports contributed to a decrease in natural gas inventories closer to historical levels.

North America

North America realized crude oil prices increased 58% to average $72.86 per bbl for the first quarter of 2008 from $46.09 per bbl for the first quarter of 2007, and increased 44% from $50.49 per bbl for the prior quarter. The increase from the comparable periods was due to the increase in WTI benchmark pricing and a narrower Heavy Differential, partially offset by the impact of the strong Canadian dollar.

In North America, the Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil conversion capacity. During the first quarter, the Company contributed approximately 153,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased marginally to average $7.80 per mcf for the first quarter of 2008 from $7.79 per mcf for the first quarter of 2007, and increased 24% from $6.31 per mcf for the prior quarter. Fluctuations in natural gas prices from the comparable periods in 2007 were primarily related to the impact of weather and storage levels.

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

		Mar 31 2008		Dec 31 2007		Mar 31 2007
Wellhead Price (1) (2)						
Light/medium crude oil and NGLs (C$/bbl)	**$**	**88.78**	$	74.96	$	59.48
Pelican Lake crude oil (C$/bbl)	**$**	**72.77**	$	47.01	$	44.44
Primary heavy crude oil (C$/bbl)	**$**	**68.61**	$	43.30	$	41.83
Thermal heavy crude oil (C$/bbl)	**$**	**65.97**	$	42.76	$	40.31
Natural gas (C$/mcf)	**$**	**7.80**	$	6.31	$	7.79

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

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

North Sea

North Sea realized crude oil prices increased 44% to average $99.01 per bbl for the first quarter of 2008 from $68.83 per bbl for the first quarter of 2007, and by 19% from $83.44 per bbl for the prior quarter. As revenue in the North Sea is currently recognized on a liftings basis, realized crude oil prices per barrel in any particular quarter are dependant on the frequency and timing of liftings of each field. Realized crude oil prices in the North Sea during the first quarter continued to benefit from the impact of strong European and Asian demand, partially offset by the impact of the strong Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 64% to average $96.31 per bbl for the first quarter of 2008 from $58.60 per bbl for the first quarter of 2007, and increased 18% from $81.89 per bbl for the prior quarter. As revenue in Offshore West Africa is recognized on a liftings basis, realized crude oil prices per barrel in any particular quarter are dependant on the frequency and timing of liftings of each field, as well as the terms of the related sales contracts. Realized crude oil prices in Offshore West Africa during the first quarter continued to benefit from the impact of strong European and Asian demand, offset by the impact of the strong Canadian dollar.

Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. The related crude oil volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	**Mar 31 2008**	Dec 31 2007	Mar 31 2007
North America, related to pipeline fill	**1,097,526**	1,097,526	1,097,526
North Sea, related to timing of liftings	**637,755**	1,032,723	401,296
Offshore West Africa, related to timing of liftings	**260,649**	8,578	230,623
	1,995,930	2,138,827	1,729,445

In the first quarter of 2008, an additional 143,000 barrels of crude oil produced in the Company's international operations, which were deferred and included in inventory at December 31, 2007, were sold. Notwithstanding the overall reduction, consolidated cash flow from operations decreased by approximately $6 million in the first quarter of 2008 as the increase in cash flow derived from additional sales volumes in the North Sea was more than offset by the decrease in cash flow due to lower sales volumes in Offshore West Africa where netbacks are higher.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
Crude oil and NGLs (bbl/d)			
North America	**248,960**	256,843	237,489
North Sea	**49,568**	52,709	61,869
Offshore West Africa	**28,689**	27,688	27,643
	327,217	337,240	327,001
Natural gas (mmcf/d)			
North America	**1,513**	1,562	1,694
North Sea	**11**	13	15
Offshore West Africa	**14**	14	8
	1,538	1,589	1,717
Total barrels of oil equivalent (boe/d)	**583,488**	601,908	613,114
Product mix			
Light/medium crude oil and NGLs	**23%**	23%	24%
Pelican Lake crude oil	**6%**	6%	5%
Primary heavy crude oil	**15%**	15%	15%
Thermal heavy crude oil	**12%**	12%	9%
Natural gas	**44%**	44%	47%

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
Crude oil and NGLs (bbl/d)			
North America	**216,585**	217,886	204,401
North Sea	**49,473**	52,586	61,754
Offshore West Africa	**23,496**	25,123	25,897
	289,554	295,595	292,052
Natural gas (mmcf/d)			
North America	**1,260**	1,327	1,367
North Sea	**11**	13	15
Offshore West Africa	**11**	12	8
	1,282	1,352	1,390
Total barrels of oil equivalent (boe/d)	**503,250**	520,887	523,730

Daily production and per barrel statistics are presented throughout this MD&A on a “before royalty” or “gross” basis. Production on an “after royalty” or “net” basis is also presented.

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 and thermal heavy crude oil.

Total production averaged 583,488 boe/d for the first quarter of 2008, a 5% decrease from 613,114 boe/d for the first quarter of 2007, and a 3% decrease from 601,908 boe/d for the prior quarter.

Total crude oil and NGLs production for the first quarter of 2008 of 327,217 bbl/d was comparable to 327,001 bbl/d for the first quarter of 2007, and decreased 3% from 337,240 bbl/d for the prior quarter. The decrease from the prior quarter was primarily due to lower production in North America and the North Sea. Crude oil and NGLs production in the first quarter of 2008 was within the Company’s previously issued guidance of 315,000 to 331,000 bbl/d.

Natural gas production continued to represent the Company’s largest product offering, accounting for 44% of the Company’s total production. Natural gas production for the first quarter of 2008 averaged 1,538 mmcf/d compared to 1,717 mmcf/d for the first quarter of 2007 and 1,589 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. First quarter natural gas production was within the Company’s previously issued guidance of 1,522 to 1,557 mmcf/d.

For 2008, annual production guidance is targeted to average between 316,000 and 366,000 bbl/d of crude oil and NGLs and between 1,429 and 1,513 mmcf/d of natural gas. Second quarter 2008 production guidance is targeted to average between 306,000 and 323,000 bbl/d of crude oil and NGLs and between 1,479 and 1,513 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for the first quarter of 2008 increased 5% to average 248,960 bbl/d from 237,489 bbl/d for the first quarter of 2007, and decreased 3% from 256,843 bbl/d for the prior quarter. The fluctuations in crude oil and NGLs production from the prior periods was primarily due to the cyclic nature of the Company’s thermal production.

For the first quarter of 2008, natural gas production decreased 11% to 1,513 mmcf/d from 1,694 mmcf/d for the first quarter of 2007, and decreased 3% from 1,562 mmcf/d for the prior quarter. The decrease in natural gas production from the prior periods reflected production declines due to the Company’s strategic decision to reduce natural gas drilling activity.

North Sea

North Sea crude oil production for the first quarter of 2008 decreased 20% to 49,568 bbl/d from 61,869 bbl/d for the first quarter of 2007 and by 6% from 52,709 bbl/d for the prior quarter. Production decreased from the prior quarter due to the sale of the Company’s interests in the B-Block Fields in December 2007, higher than anticipated downtime on the Banff Field and further decline of the 2007 Lyell subsea wells.

Offshore West Africa

Offshore West Africa crude oil production increased 4% to 28,689 bbl/d for the first quarter of 2008 from 27,643 bbl/d for the first quarter of 2007, and by 4% from 27,688 bbl/d for the prior quarter. Production increased compared with the comparable periods in 2007 due to the progress on the West Espoir drilling program, which was successfully completed in January 2008, coupled with stable production from the Baobab Field. In Baobab, the Company has secured a deepwater rig, on location in April 2008, which should enable the Company to execute its plan to restore certain of its shut-in production over the course of 2008 and 2009.

ROYALTIES

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 9.63**	$ 7.66	$ 6.42
North Sea	**$ 0.19**	$ 0.19	$ 0.13
Offshore West Africa	**$ 17.43**	$ 7.59	$ 3.70
Company average	**$ 8.70**	$ 6.66	$ 4.92
Natural gas ($/mcf) [1]			
North America	**$ 1.36**	$ 0.95	$ 1.50
Offshore West Africa	**$ 1.43**	$ 0.52	$ 0.38
Company average	**$ 1.35**	$ 0.94	$ 1.48
Company average ($/boe) [1]	**$ 8.43**	$ 6.21	$ 6.76
Percentage of revenue [2]			
Crude oil and NGLs	**11%**	11%	10%
Natural gas	**17%**	15%	19%
Boe	**13%**	13%	14%

(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 crude oil and NGLs royalties per bbl for the first quarter of 2008 continue to reflect strong realized crude oil prices. Crude oil and NGLs royalties averaged approximately 13% of revenues for the first quarter of 2008, compared to 14% for the first quarter in 2007 and 15% in the prior quarter. Crude oil and NGLs royalties per bbl are anticipated to average 14% to 16% of gross revenue for 2008.

Natural gas royalties per mcf generally fluctuate with natural gas prices. Natural gas royalties averaged approximately 17% of revenues for the first quarter of 2008 compared to 19% for the first quarter of 2007 and 15% for the prior quarter. Natural gas royalties are anticipated to average 17% to 20% of gross revenue for 2008.

North Sea

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining royalty is a gross overriding royalty on the Ninian Field.

Offshore West Africa

Offshore West Africa production is governed by the terms of the various Production Sharing Contracts ("PSCs"). Under the PSCs, revenues are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the Government State Oil Company. Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's share of profit oil attributable to the Company's equity interest is allocated between royalty expense and current income tax expense in accordance with the PSCs. The Company's capital investments in the Espoir Fields were fully recovered in the first quarter of 2007, increasing royalty rates and current income taxes in accordance with the terms of the PSCs.

Royalty rates as a percentage of revenue averaged approximately 18% for the first quarter of 2008 compared to 6% for the first quarter of 2007 and 9% for the prior quarter. Royalty expense in the first quarter reflected the relatively high proportion of Espoir sales in the period and the increase in allocation of the Government's share to royalties due to the reduction in the Côte d'Ivoire corporate income tax rate enacted in the first quarter of 2008. Offshore West Africa royalty rates are anticipated to average 12% to 17% of gross revenue for 2008.

PRODUCTION EXPENSE

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 13.88**	$ 10.54	$ 13.00
North Sea	**$ 22.35**	$ 18.95	$ 18.57
Offshore West Africa	**$ 8.03**	$ 9.32	$ 8.93
Company average	**$ 14.81**	$ 11.53	$ 13.81
Natural gas ($/mcf) (1)			
North America	**$ 1.01**	$ 0.90	$ 0.95
North Sea	**$ 2.33**	$ 1.50	$ 2.58
Offshore West Africa	**$ 1.25**	$ 1.89	$ 1.48
Company average	**$ 1.03**	$ 0.91	$ 0.97
Company average ($/boe) (1)	**$ 11.02**	$ 8.85	$ 10.10

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

North America

North America crude oil and NGLs production expense for the first quarter of 2008 increased 7% to $13.88 per bbl from $13.00 per bbl for the first quarter of 2007 and increased 32% from $10.54 per bbl for the prior quarter. The increase in production expense per barrel for the first quarter of 2008 was a result of the timing of steam cycles, higher cost of natural gas for fuel for the Company's thermal operations, and increased seasonal costs related to winter access areas.

North America natural gas production expense for the first quarter of 2008 increased 6% to $1.01 per mcf from $0.95 per mcf for the first quarter of 2007 and increased 12% from $0.90 per mcf for the prior quarter. The increase in production expense per mcf was a result of lower sales volumes on the fixed cost portion of production costs and increased seasonal costs related to winter access areas.

North Sea

North Sea crude oil production expense increased on a per barrel basis from the comparable quarters in 2007 due to lower production volumes on a relatively fixed cost base and the timing of liftings from various fields.

Offshore West Africa

Offshore West Africa crude oil production expense decreased on a per barrel basis from the comparable quarters in 2007 primarily due to the impact of the timing of liftings at the Baobab and Espoir Fields, resulting in a greater proportion of relatively lower fixed cost Espoir sales in the quarter.

MIDSTREAM

	Three Months Ended		
($ millions)	**Mar 31 2008**	Dec 31 2007	Mar 31 2007
Revenue	**$ 20**	$ 19	$ 19
Production expense	**5**	6	6
Midstream cash flow	**15**	13	13
Depreciation	**2**	2	2
Segment earnings before taxes	**$ 13**	$ 11	$ 11

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to control the transport of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

DEPLETION, DEPRECIATION AND AMORTIZATION (1)

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
Expense ($ millions)	**$ 686**	$ 717	$ 707
$/boe (2)	**$ 12.87**	$ 12.99	$ 12.73

(1) DD&A excludes depreciation on midstream assets.

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

Depletion, Depreciation and Amortization ("DD&A") for the first quarter of 2008 decreased in total from the prior quarter and the first quarter of 2007. The decrease in DD&A expense from the prior periods was primarily due to the impact of lower sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
Expense ($ millions)	**$ 17**	$ 17	$ 18
$/boe (1)	**$ 0.31**	$ 0.31	$ 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. Accretion expense for the first quarter of 2008 was consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
Expense ($ millions)	**$ 43**	$ 42	$ 60
$/boe (1)	**$ 0.80**	$ 0.76	$ 1.08

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

Administration expense for the first quarter of 2008 decreased in total and on a boe basis from the first quarter of 2007 primarily due to decreased staffing costs, including costs related to the Company's share bonus program.

STOCK-BASED COMPENSATION EXPENSE (RECOVERY)

	Three Months Ended		
($ millions)	**Mar 31 2008**	Dec 31 2007	Mar 31 2007
Expense (recovery)	**$ -**	$ (16)	$ 25

The Company's Stock Option Plan (the "Option Plan") provides current employees (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The design of the Option Plan balances the need for a long-term compensation program to retain employees with the benefits of reducing the impact of dilution on current Shareholders and the reporting of the obligations associated with stock options. Transparency of the cost of the Option Plan is increased since changes in the intrinsic value of outstanding stock options are recognized each period. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

For the first quarter of 2008, no stock-based compensation expense was recognized as the expense associated with options vesting in the normal course was offset by the impact of the lower share price at March 31, 2008 (Company's share price as at: March 31, 2008 - C$70.27; December 31, 2007 - C$72.58; March 31, 2007 - C$63.75; December 31, 2006 - C$62.15). As required by GAAP, the Company's outstanding stock options are valued each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in net earnings, or capitalized during the construction period in the case of the Horizon Project. For the three months ended March 31, 2008, the Company recorded a $5 million recovery on previously capitalized stock-based compensation on the Horizon Project (March 31, 2007 - $9 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 March 31, 2008. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the three months ended March 31, 2008, the Company paid $80 million for stock options surrendered for cash settlement (March 31, 2007 - $136 million).

INTEREST EXPENSE

	Three Months Ended		
($ millions, except per boe amounts)	**Mar 31 2008**	Dec 31 2007	Mar 31 2007
Expense, gross	**$ 160**	$ 160	$ 154
Less: capitalized interest, Horizon Project	**111**	109	71
Expense, net	**$ 49**	$ 51	$ 83
$/boe (1)	**$ 0.92**	$ 0.92	$ 1.49
Average effective interest rate	**5.5%**	5.5%	5.4%

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

Gross interest expense and the Company's average effective interest rate increased from the first quarter in 2007 primarily due to an increased proportion of higher cost US dollar denominated debt, offset by decreased short term borrowing rates in the first quarter of 2008 and the impact of the strong Canadian dollar.

On commencement of operations of Phase 1 of the Horizon Project, interest capitalization will cease on this Phase, increasing 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.

	Three Months Ended		
($ millions)	**Mar 31 2008**	Dec 31 2007	Mar 31 2007
Crude oil and NGLs financial instruments	**$ 463**	$ 308	$ (5)
Natural gas financial instruments	**(47)**	(127)	(83)
Realized loss (gain)	**$ 416**	$ 181	$ (88)
Crude oil and NGLs financial instruments	**$ 51**	$ 770	$ 330
Natural gas financial instruments	**59**	75	206
Foreign currency swaps	**(2)**	-	-
Unrealized loss	**$ 108**	$ 845	$ 536
Net loss	**$ 524**	$ 1,026	$ 448

The net realized loss (gain) from crude oil and natural gas financial instruments would have decreased (increased) the Company's average realized prices as follows:

	Three Months Ended		
	Mar 31 2008	Dec 31 2007	Mar 31 2007
Crude oil and NGLs ($/bbl) (1)	**$ 15.47**	$ 9.99	$ (0.17)
Natural gas ($/mcf) (1)	**$ (0.33)**	$ (0.87)	$ (0.54)

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

Complete details related to outstanding derivative financial instruments at March 31, 2008 are disclosed in note 10 to the Company's unaudited interim consolidated financial statements.

The commodity derivative financial instruments currently outstanding have not been designated as hedges for accounting purposes (the "non-designated hedges"). The fair value of these non-designated hedges is based on prevailing forward commodity prices in effect at the end of each reporting period and is reflected in risk management activities in consolidated net earnings. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at March 31, 2008. 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 $108 million ($76 million after-tax) on its commodity risk management activities for the three months ended March 31, 2008 (December 31, 2007 - unrealized loss of $845 million, $593 million after-tax; March 31, 2007 - unrealized loss of $536 million, $362 million after-tax).

FOREIGN EXCHANGE

	Three Months Ended		
($ millions)	**Mar 31 2008**	Dec 31 2007	Mar 31 2007
Net realized (gain) loss	**$ (12)**	$ -	$ 5
Net unrealized loss (gain) [1]	**126**	(47)	(32)
Net loss (gain)	**$ 114**	$ (47)	$ (27)

(1) Amounts are reported net of the hedging effect of cross currency swaps as described in Risk Management Activities.

The Company's operating results are affected by fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. A majority of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in decreased revenue from the sale of the Company's production. Conversely, a decrease in the value of the Canadian dollar in relation to the US dollar results in increased revenue from the sale of the Company's production. Production expenses in the North Sea are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar, while production expenses in Offshore West Africa are subject to foreign currency fluctuations due to changes in the exchange rate of the Canadian dollar to the US dollar. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The net unrealized foreign exchange loss for the first quarter of 2008 was primarily related to the weakening of the Canadian dollar in relation to the US dollar with respect to the US dollar debt, together with the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars. Included in the net unrealized loss for the three months ended March 31, 2008 was an unrealized gain of $75 million (three months ended March 31, 2007 - unrealized loss of $37 million) related to the impact of the cross currency swaps. The net realized foreign exchange gain for the three months ended March 31, 2008 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the first quarter at US$0.9729 compared to US$1.0120 at December 31, 2007 (March 31, 2007 - US$0.8674).

TAXES

($ millions, except income tax rates)	Three Months Ended Mar 31 2008	Dec 31 2007	Mar 31 2007
Current	$ 70	$ 16	$ 66
Deferred	(21)	17	(3)
Taxes other than income tax	$ 49	$ 33	$ 63
North America	$ 21	$ 31	$ 25
North Sea	96	65	35
Offshore West Africa	38	27	10
Current income tax	155	123	70
Future income tax expense (recovery)	80	(847)	100
	235	(724)	170
Income tax rate and other legislative changes (1) (2)	41	793	-
	$ 276	$ 69	$ 170
Effective income tax rate before non-recurring benefits	28.7%	93.2%	38.7%

(1) 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 enacted or substantively enacted during the first quarter of 2008.

(2) Includes the effect of a one time recovery of $793 million due to Canadian Federal income tax rate reductions and other legislative changes enacted or substantively enacted during the fourth quarter of 2007.

Taxes other than income tax primarily includes current and deferred petroleum revenue tax ("PRT"). PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including abandonment expenditures.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in a future period. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature, timing and amount of capital expenditures incurred in Canada in any particular year. In particular, current taxes in a specific year are sensitive to the timing of when the Horizon Project capital expenditures are deductible for Canadian income tax purposes.

CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Mar 31 2008	Dec 31 2007	Mar 31 2007
Expenditures on property, plant and equipment			
Net property (dispositions) acquisitions	**$ (8)**	$ (107)	$ 46
Land acquisition and retention	**12**	15	29
Seismic evaluations	**27**	17	50
Well drilling, completion and equipping	**452**	341	714
Production and related facilities	**319**	390	334
Total net reserve replacement expenditures	**802**	656	1,173
Horizon Project:			
Phase 1 construction costs	**665**	691	674
Phase 1 operating and capital inventory	**41**	-	-
Phase 1 commissioning costs	**49**	-	-
Phases 2/3 costs	**77**	33	44
Capitalized interest, stock-based compensation and other	**109**	108	91
Total Horizon Project	**941**	832	809
Midstream	**1**	2	2
Abandonments [2]	**6**	16	20
Head office	**3**	8	5
Total net capital expenditures	**$ 1,753**	$ 1,514	$ 2,009
By segment			
North America	**$ 663**	$ 570	$ 998
North Sea	**45**	44	138
Offshore West Africa	**94**	43	36
Other	**-**	(1)	1
Horizon Project	**941**	832	809
Midstream	**1**	2	2
Abandonments [2]	**6**	16	20
Head office	**3**	8	5
Total	**$ 1,753**	$ 1,514	$ 2,009

(1) The net capital expenditures exclude adjustments related to differences between carrying value and tax value.

(2) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

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

Net capital expenditures for the three months ended March 31, 2008 were $1,753 million compared to $2,009 million for the three months ended March 31, 2007. Capital expenditures in the first quarter of 2008 primarily reflected the continued progress on the Company's larger, future growth projects, most notably the Horizon Project, offset by the effects of an overall strategic reduction in the North America natural gas drilling program.

For the three months ended March 31, 2008, the Company drilled a total of 360 net wells consisting of 161 natural gas wells, 173 crude oil wells, 15 stratigraphic test and service wells and 11 wells that were dry. This compared to 688 net wells drilled for the three months ended March 31, 2007 and 271 net wells drilled in the prior quarter. The Company achieved an overall success rate of 97% for the three months ended March 31, 2008, excluding stratigraphic test and service wells, compared to 87% for the first quarter of 2007 and 94% for the prior quarter.

North America

North America, including the Horizon Project, accounted for approximately 92% of the total capital expenditures for the three months ended March 31, 2008 compared to approximately 91% for the first quarter of 2007 and 94% for the prior quarter.

During the first quarter of 2008, the Company targeted 167 net natural gas wells, including 20 wells in Northeast British Columbia, 44 wells in the Northern Plains region, 50 wells in Northwest Alberta, and 53 wells in the Southern Plains region. The Company also targeted 176 net crude oil wells during the same period. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 96 heavy crude oil wells, 25 Pelican Lake crude oil wells, 22 thermal crude oil wells and 4 light crude oil wells were drilled. Another 29 wells targeting light crude oil were drilled outside the Northern Plains region.

Due to significant changes in relative commodity prices between crude oil and natural gas during the first quarter of 2008, 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 2007 and 2008, 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 first quarter of 2008 averaged approximately 69,000 bbl/d compared to approximately 58,000 bbl/d for the first quarter of 2007 and approximately 74,000 bbl/d for the prior quarter.

The Primrose East Expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility, is anticipated to add approximately 40,000 bbl/d when complete. Drilling and construction are currently underway, and production is targeted to commence in 2009.

The next phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 kilometers north of the existing Primrose facilities. The Kirby project is anticipated to add approximately 45,000 bbl/d of production growth. During 2007, the Company filed a combined application and Environmental Impact Assessment for this project with Alberta Environment and the Alberta Energy and Utilities Board. Final corporate sanction and project scope will be impacted by environmental regulations and their associated costs.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout the first quarter of 2008. Drilling consisted of 25 horizontal wells in the first quarter. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 37,000 bbl/d for the first quarter of 2008 compared to 32,000 bbl/d for the first quarter of 2007 and approximately 36,000 bbl/d for the prior quarter.

For the second quarter of 2008, the Company's overall drilling activity in North America is expected to be comprised of 8 natural gas wells and 62 crude oil wells excluding stratigraphic and service wells.

Horizon Project

Work progress on the Horizon Project was 94% complete at the end of the first quarter. First production is targeted to commence in the third quarter of 2008. The project status as at March 31, 2008 was as follows:

- Site assembly of Mine Operations equipment (Shovels and Heavy Haul Trucks) is on schedule;
- Fixed Plant Maintenance contractors have been mobilized;
- All oversized loads for construction have been delivered to site. Ongoing deliveries of mine equipment (trucks and shovels) will continue through the summer;
- Overall construction 91% completed;
- Mine overburden removal has moved 56.7 million bank cubic meters, which represents approximately 80% of the total to be moved before start up;
- Completed Tar River Diversion and Fish Habitat construction;
- Substantially completed Extraction Plant in the first quarter and have introduced water to the plant in April;
- Completed construction of Tanks 11 and 12 in the East Tank Farm and filled with diluent for start up;
- Installed 3 nitrogen storage tanks and completed construction of the Nitrogen Plant, now ready for operations;
- Installed Auxiliary Boiler in Cogeneration;
- Assumed occupancy of Main Warehouse;
- Substations energized for Sulphur Recovery and Gas Treating, representing the last on-site substations to be energized;
- Substantially completed construction of Amine Plant and moving into Pre-Commissioning;
- Started construction of Sulphur pipeline;
- Completed piping in Heat Integration.

The Company has budgeted construction costs of approximately $1.1 billion to $1.3 billion for the remainder of 2008 related to the planned completion of Phase 1 of the Horizon Project.

North Sea

In the first quarter of 2008, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the quarter, 1.6 net wells were drilled, with an additional 1.6 net wells drilling at the end of the quarter.

At Ninian, the Company continued with its planned investment in its long-term facilities and infrastructure strategy. One well was converted to water injection during the quarter and a further water injection well is drilling and due for completion in the second quarter. At the Murchison Platform, the first of 2 production wells planned for 2008 was completed, with the second scheduled for completion in the second quarter. At Columba E, the Company successfully increased water injection rates, thereby increasing reservoir pressure with the goal of increasing production.

Offshore West Africa

During the first quarter of 2008, 0.6 net wells were drilled.

Crude oil production from West Espoir commenced in mid 2006 with the final production well in the program added during the first quarter of 2008. The drilling program was completed on budget and on schedule.

At the 90% owned and operated Olowi Field in offshore Gabon, all major construction contracts have been awarded and construction activity on the wellhead towers, subsea facilities and the floating production storage and offtake vessel (“FPSO”) are progressing as planned. Drilling commenced early in the second quarter of 2008 and first crude oil is targeted for late 2008. Olowi production is targeted to plateau at approximately 20,000 bbl/d net to the Company.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Mar 31 2008**	Dec 31 2007	Mar 31 2007
Working capital deficit [1]	**$ 1,572**	$ 1,382	$ 1,104
Long-term debt [2]	**$ 11,230**	$ 10,940	$ 11,307
Share capital	**$ 2,725**	$ 2,674	$ 2,635
Retained earnings	**11,248**	10,575	8,374
Accumulated other comprehensive income (loss)	**95**	72	(45)
Shareholders' equity	**$ 14,068**	$ 13,321	$ 10,964
Debt to book capitalization [2] [3]	**44%**	45%	51%
Debt to market capitalization [2] [4]	**23%**	22%	25%
After tax return on average common shareholders' equity [5]	**24%**	22%	28%
After tax return on average capital employed [2] [6]	**14%**	12%	17%

(1) Calculated as current assets less current liabilities.

(2) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.

(3) Calculated as long-term debt; divided by the book value of common shareholders' equity plus long-term debt.

(4) Calculated as long-term debt; divided by the market value of common shareholders' equity plus long-term debt.

(5) Calculated as net earnings for the twelve month trailing period; as a percentage of average common shareholders' equity for the period.

(6) 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 long-term debt for the period, including $7,876 million in average capital employed related to the Horizon Project (December 31, 2007 - $7,001 million; March 31, 2007 - $4,507 million).

The Company's capital resources at March 31, 2008 consisted primarily of cash flow from operations, available 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, 2007 annual MD&A**.** The Company's ability to renew existing 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. Management believes internally generated cash flows supported by the implementation of the Company's hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, the Company's existing credit facilities and the Company's ability to raise new debt on commercially acceptable terms, will be sufficient to sustain its operations and support its growth strategy. The Company's current debt ratings are BBB (high) with a negative trend by DBRS Limited, Baa2 with a stable outlook by Moody's Investors Service and BBB with a stable outlook by Standard & Poor's. The Company does not have any direct exposure to asset-backed commercial paper.

At March 31, 2008, the Company had undrawn bank lines of credit of $2,626 million. Details related to the Company's long-term debt at March 31, 2008 are disclosed in note 3 to the Company's unaudited interim consolidated financial statements.

At March 31, 2008, the Company's working capital deficit was $1,572 million and included the current portion of the stock-based compensation liability of $342 million and the current portion of the net mark-to-market liability for risk management derivative financial instruments of $1,365 million. The settlement of the stock-based compensation liability is dependent upon both the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of surrender. The cash settlement amount of the risk management derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement of the derivative financial instruments, as compared to their mark-to-market value at March 31, 2008.

The Company believes it has the necessary financial capacity to complete the Horizon Project, while at the same time not compromising conventional crude oil and natural gas growth opportunities. The financing of Phase 1 of the Horizon Project development is guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet.

Long-term debt was $11,230 million at March 31, 2008, resulting in a debt to book capitalization ratio of 44% (December 31, 2007 - 45%; March 31, 2007 - 51%). While this ratio is at the high end of the 35% to 45% range targeted by management, the Company remains committed to maintaining a strong balance sheet and flexible capital structure, and expects its debt to book capitalization ratio to be near the midpoint of the range in late 2008. While the Company believes that it has the balance sheet strength and flexibility to complete Phase 1 of the Horizon Project, as well as its other planned capital expenditure programs, the Company has hedged a significant portion of its crude oil and natural gas production for 2008 at prices that protect investment returns. In the future, the Company may also consider the divestiture of certain non-strategic and non-core properties to gain additional balance sheet flexibility.

The Company's commodity hedging program reduces the risk of volatility in commodity price markets and supports the Company's cash flow for its capital expenditures throughout the Horizon Project construction period. This program currently allows for the hedging of up to 75% of the near 12 months budgeted production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48. For the purpose of this program, the purchase of put options is in addition to the above parameters. In accordance with the policy, approximately 61% of budgeted crude oil volumes are hedged for the remainder of 2008, approximately 18% of budgeted natural gas volumes are hedged for the second and third quarters of 2008 and approximately 6% of estimated crude oil volumes are hedged for 2009. In addition, 50,000 bbl/d of crude oil volumes are protected by put options for the remainder of 2008 at a strike price of US$55.00 per barrel and 50,000 bbl/d of crude oil volumes are protected by put options for 2009 at a strike price of US$80.00 per barrel.

Commencing January 1, 2009, following the planned completion of Phase 1 of the Horizon Project, the Company's commodity hedging program has been revised by its Board of Directors to allow for the hedging of up to 50% of the near 12 months budgeted production and up to 25% of the following 13 to 24 months estimated production. The purchase of put options will continue to be in addition to the above parameters.

The Company has the following commodity related net financial derivatives outstanding as at March 31, 2008:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Apr 2008	–	Jun 2008	25,000 bbl/d	US$60.00	–	US$80.44	WTI
	Apr 2008	–	Sep 2008	25,000 bbl/d	US$60.00	–	US$80.46	WTI
	Jul 2008	–	Sep 2008	25,000 bbl/d	US$70.00	–	US$123.75	WTI
	Apr 2008	–	Dec 2008	20,000 bbl/d	US$50.00	–	US$65.53	Mayan Heavy
	Apr 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$75.22	WTI
	Apr 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.05	WTI
	Apr 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.98	WTI
	Oct 2008	–	Dec 2008	25,000 bbl/d	US$70.00	–	US$112.63	WTI
	Jan 2009	–	Dec 2009	25,000 bbl/d	US$70.00	–	US$111.56	WTI
Crude oil puts	Apr 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
	Jan 2009	–	Dec 2009	50,000 bbl/d			US$80.00	WTI
Natural gas								
AECO price collars	Apr 2008	–	Sep 2008	290,000 GJ/d	C$7.50	–	C$8.69	AECO

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

Long-term debt

As at March 31, 2008, the Company had in place unsecured bank credit facilities of $6,211 million, comprised of:

- a $100 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 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.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $351 million, including $300 million related to the Horizon Project, were outstanding at March 31, 2008.

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.

US dollar debt securities

In January 2008, the Company issued US$1,200 million of unsecured notes under a US base shelf prospectus, comprised of US$400 million of 5.15% unsecured notes due February 2013, US$400 million of 5.90% unsecured notes due February 2018, and US$400 million of 6.75% unsecured notes due February 2039. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these 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.

Share capital

As at March 31, 2008, there were 540,465,000 common shares outstanding and 27,835,000 stock options outstanding. As at May 6, 2008, the Company had 540,543,000 common shares outstanding and 26,659,000 stock options outstanding.

The Company did not purchase any common shares for cancellation pursuant to the Normal Course Issuer Bid previously filed for the twelve month period beginning January 24, 2007 and ending January 23, 2008. The Company has decided not to renew the Normal Course Issuer Bid until subsequent to the completion of Phase 1 of the Horizon Project.

In February 2008, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.40 per common share for 2008. The increase represents an 18% increase from 2007, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the eighth consecutive year in which the Company has paid dividends and the seventh consecutive year of an increase in the distribution paid to its 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. These commitments primarily relate to debt repayments; operating leases relating to offshore FPSOs, drilling rigs and office space; firm commitments for gathering, processing and transmission services; as well as expenditures relating to asset retirement obligations. As at March 31, 2008, no entities were consolidated under the Canadian Institute of Chartered Accountants Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at March 31, 2008:

($ millions)	Remaining 2008	2009	2010	2011	2012	Thereafter
Product transportation and pipeline	$ 180	$ 163	$ 149	$ 123	$ 107	$ 1,099
Offshore equipment operating lease (1)	$ 98	$ 130	$ 118	$ 116	$ 94	$ 405
Offshore drilling (2) (3)	$ 274	$ 187	$ 47	$ -	$ -	$ -
Asset retirement obligations (4)	$ 28	$ 4	$ 5	$ 4	$ 4	$ 4,484
Long-term debt (5)	$ 40	$ 2,374	$ 400	$ 411	$ 360	$ 6,505
Interest expense (6)	$ 429	$ 586	$ 499	$ 477	$ 424	$ 5,390
Office lease	$ 19	$ 26	$ 29	$ 22	$ 2	$ -
Electricity and other	$ 126	$ 267	$ 162	$ 4	$ -	$ -

(1) Offshore equipment operating leases are primarily comprised of obligations related to FPSOs. During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. During the initial term, the total annual payments for the Gabon FPSO are estimated to be US$50 million.

(2) During 2007, the Company entered into a one-year agreement for offshore drilling services related to the Baobab Field in Côte d'Ivoire, Offshore West Africa. The agreement is scheduled to commence in the second quarter of 2008, on delivery of the rig. Estimated total payments of US$100 million, after joint venture recoveries, have been included in this table for the period 2008 - 2009.

(3) During 2007, the Company awarded contracts for a drilling rig and for the construction of wellhead towers in connection with the planned offshore development in Gabon, Offshore West Africa. Estimated total payments of US$392 million have been included in this table for the period 2008 - 2010.

(4) 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 2008 - 2012 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(5) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,182 million of revolving bank credit facilities due to the extendable nature of the facilities.

(6) 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 as at March 31, 2008.

In addition to the amounts disclosed above, the Company has budgeted construction costs of approximately $1.1 billion to $1.3 billion for the remainder of 2008 related to the planned completion of Phase 1 of the Horizon Project.

Legal proceedings

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. In addition, the Company is subject to certain contractor construction claims related to the Horizon Project. 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, 2007.

For the impact of new accounting standards related to capital disclosures, inventory and financial instruments, refer to note 2 of the unaudited interim consolidated financial statements as at March 31, 2008.

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the first quarter of 2008, 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	$ 95	$ 0.18	$ 70	$ 0.13
Including financial derivatives	$ 40	$ 0.07	$ 31	$ 0.06
Natural gas – AECO C$0.10/mcf (1)				
Excluding financial derivatives	$ 40	$ 0.07	$ 28	$ 0.05
Including financial derivatives	$ 35	$ 0.06	$ 25	$ 0.05
Volume changes				
Crude oil – 10,000 bbl/d	$ 177	$ 0.33	$ 106	$ 0.20
Natural gas – 10 mmcf/d	$ 20	$ 0.04	$ 9	$ 0.02
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 87 – 89	$ 0.16	$ 30	$ 0.05 – 0.06
Interest rate change - 1%	$ 30	$ 0.06	$ 30	$ 0.06

(1) For details of outstanding financial instruments in place, refer to note 10 of the Company's unaudited interim consolidated financial statements.

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS

	Three Months Ended		
($/boe) [1]	**Mar 31 2008**	Dec 31 2007	Mar 31 2007
Sales price [2]	**$ 65.09**	$ 49.23	$ 49.32
Royalties	**8.43**	6.21	6.76
Production expense [3]	**11.02**	8.85	10.10
Netback	**45.64**	34.17	32.46
Midstream contribution [3]	**(0.27)**	(0.24)	(0.24)
Administration	**0.80**	0.76	1.08
Interest, net	**0.92**	0.92	1.49
Realized risk management loss (gain)	**7.82**	3.27	(1.58)
Realized foreign exchange (gain) loss	**(0.22)**	-	0.10
Taxes other than income tax - current	**1.32**	0.30	1.18
Current income tax - North America	**0.40**	0.56	0.45
Current income tax - North Sea	**1.79**	1.18	0.62
Current income tax - Offshore West Africa	**0.71**	0.50	0.18
Cash flow	**$ 32.37**	$ 26.92	$ 29.18

(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) Excluding intersegment elimination.

FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)	**Mar 31 2008**	Dec 31 2007
ASSETS		
Current assets		
Cash and cash equivalents	**$ 27**	$ 21
Accounts receivable and other	**2,135**	1,662
Future income tax	**506**	480
Current portion of other long-term assets	**-**	18
	2,668	2,181
Property, plant and equipment (note 12)	**35,051**	33,902
Other long-term assets	**36**	31
	$ 37,755	$ 36,114
LIABILITIES		
Current liabilities		
Accounts payable	**$ 455**	$ 379
Accrued liabilities	**2,078**	1,567
Current portion of other long-term liabilities (note 4)	**1,707**	1,617
	4,240	3,563
Long-term debt (note 3)	**11,230**	10,940
Other long-term liabilities (note 4)	**1,386**	1,561
Future income tax	**6,831**	6,729
	23,687	22,793
SHAREHOLDERS' EQUITY		
Share capital (note 6)	**2,725**	2,674
Retained earnings	**11,248**	10,575
Accumulated other comprehensive income (note 7)	**95**	72
	14,068	13,321
	$ 37,755	$ 36,114

Commitments (note 11)

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Mar 31 2008		Mar 31 2007	
Revenue	**$**	**3,967**	$	3,118
Less: royalties		**(449)**		(376)
Revenue, net of royalties		**3,518**		2,742
Expenses				
Production		**587**		565
Transportation and blending		**485**		359
Depletion, depreciation and amortization		**688**		709
Asset retirement obligation accretion (note 4)		**17**		18
Administration		**43**		60
Stock-based compensation expense (note 4)		**-**		25
Interest, net		**49**		83
Risk management activities (note 10)		**524**		448
Foreign exchange loss (gain)		**114**		(27)
		2,507		2,240
Earnings before taxes		**1,011**		502
Taxes other than income tax		**49**		63
Current income tax expense (note 5)		**155**		70
Future income tax expense (note 5)		**80**		100
Net earnings	**$**	**727**	$	269
Net earnings per common share (note 9)				
Basic and diluted	**$**	**1.35**	$	0.50

Consolidated Statements of Shareholders' Equity

(millions of Canadian dollars, unaudited)	Three Months Ended **Mar 31 2008**	Mar 31 2007
Share capital (note 6)		
Balance – beginning of period	**$ 2,674**	$ 2,562
Issued upon exercise of stock options	**9**	13
Previously recognized liability on stock options exercised for common shares	**42**	60
Balance – end of period	**2,725**	2,635
Retained earnings		
Balance – beginning of period	**10,575**	8,151
Net earnings	**727**	269
Dividends on common shares (note 6)	**(54)**	(46)
Balance – end of period	**11,248**	8,374
Accumulated other comprehensive income (loss) (note 7)		
Balance – beginning of period	**72**	146
Other comprehensive income (loss), net of taxes	**23**	(191)
Balance – end of period	**95**	(45)
Shareholders' equity	**$ 14,068**	$ 10,964

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)	Three Months Ended **Mar 31 2008**	Mar 31 2007
Net earnings	**$ 727**	$ 269
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized income during the period, net of taxes of $2 million (2007 – $55 million)	**24**	(116)
Reclassification to net earnings, net of taxes of $8 million (2007 – $35 million)	**(17)**	(74)
	7	(190)
Foreign currency translation adjustment		
Translation of net investment	**16**	(1)
Other comprehensive income (loss), net of taxes	**23**	(191)
Comprehensive income	**$ 750**	$ 78

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Three Months Ended **Mar 31 2008**	Mar 31 2007
Operating activities		
Net earnings	**$ 727**	$ 269
Non-cash items		
Depletion, depreciation and amortization	**688**	709
Asset retirement obligation accretion	**17**	18
Stock-based compensation expense	**-**	25
Unrealized risk management loss	**108**	536
Unrealized foreign exchange loss (gain)	**126**	(32)
Deferred petroleum revenue tax recovery	**(21)**	(3)
Future income tax expense	**80**	100
Other	**13**	(13)
Abandonment expenditures	**(6)**	(20)
Net change in non-cash working capital	**(166)**	(119)
	1,566	1,470
Financing activities		
Repayment of bank credit facilities, net	**(1,172)**	(2,013)
Repayment of medium-term notes	**-**	(125)
Issue of US dollar debt securities	**1,223**	2,553
Issue of common shares on exercise of stock options	**9**	13
Dividends on common shares	**(46)**	(40)
Net change in non-cash working capital	**5**	(22)
	19	366
Investing activities		
Expenditures on property, plant and equipment	**(1,756)**	(1,993)
Net proceeds on sale of property, plant and equipment	**9**	4
Net expenditures on property, plant and equipment	**(1,747)**	(1,989)
Net change in non-cash working capital	**168**	144
	(1,579)	(1,845)
Increase (decrease) in cash and cash equivalents	**6**	(9)
Cash and cash equivalents – beginning of period	**21**	23
Cash and cash equivalents – end of period	**$ 27**	$ 14
Interest paid	**$ 146**	$ 158
Taxes paid		
Taxes other than income tax	**$ 31**	$ 35
Current income tax	**$ 53**	$ 71

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, 2007, 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, 2007.

Comparative Figures

Certain prior period figures have been reclassified to conform to the presentation adopted in 2008.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2008 the Company adopted the following accounting and disclosure standards issued by the Canadian Institute of Chartered Accountants:

- **Capital Disclosures** – Section 1535 – “Capital Disclosures” requires entities to disclose their objectives, policies and processes for managing capital, as well as quantitative data about capital. The standard also requires the disclosure of any externally imposed capital requirements and compliance with those requirements. The standard does not define capital. This standard affects disclosure only and did not impact the Company’s accounting for capital (note 8).

- **Inventories** – Section 3031 – “Inventories” replaces Section 3030 – “Inventories” and establishes new standards for the measurement of cost of inventories and expands disclosure requirements for inventories. Adoption of this standard did not have a material impact on the Company’s financial statements.

- **Financial Instruments** – Section 3862 – “Financial Instruments – Disclosure” and Section 3863 – “Financial Instruments – Presentation” replace Section 3861 – “Financial Instruments – Disclosure and Presentation”. Section 3862 enhances disclosure requirements concerning risks and requires quantitative and qualitative disclosures about exposures to risks arising from financial instruments. Section 3863 carries forward the presentation requirements from Section 3861 unchanged. These standards affect disclosures only and do not impact the Company’s accounting for financial instruments (note 10).

3. LONG–TERM DEBT

	Mar 31 2008	Dec 31 2007
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	**$ 3,524**	$ 4,696
Medium-term notes	**1,200**	1,200
	4,724	5,896
US dollar denominated debt		
Senior unsecured notes (2008 - US$62 million; 2007 - US$62 million)	**64**	61
US dollar debt securities (2008 - US$6,308 million; 2007 - US$5,108 million)	**6,484**	5,048
Less – original issue discount on senior unsecured notes and US dollar debt securities [(1)]	**(24)**	(23)
	6,524	5,086
Fair value of interest rate swaps on US dollar debt securities [(2)]	**41**	9
	6,565	5,095
Long-term debt before transaction costs	**11,289**	10,991
Less – transaction costs [(1) (3)]	**(59)**	(51)
	$ 11,230	$ 10,940

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

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $41 million (2007 - $9 million) to reflect the fair value impact of hedge accounting.

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

Bank credit facilities

As at March 31, 2008, the Company had in place unsecured bank credit facilities of $6,211 million, comprised of:

- a $100 million demand credit facility;
- a non-revolving syndicated credit facility of $2,350 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.

The weighted average interest rate of the bank credit facilities outstanding at March 31, 2008, was 4.3% (December 31, 2007 - 5.2%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $351 million, including $300 million related to the Horizon Oil Sands Project ("Horizon Project"), were outstanding at March 31, 2008.

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.

US dollar debt securities

In January 2008, the Company issued US$1,200 million of unsecured notes under a US base shelf prospectus, comprised of US$400 million of 5.15% unsecured notes due February 2013, US$400 million of 5.90% unsecured notes due February 2018, and US$400 million of 6.75% unsecured notes due February 2039. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these 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.

4. OTHER LONG–TERM LIABILITIES

	Mar 31 2008	Dec 31 2007
Asset retirement obligations	**$ 1,110**	$ 1,074
Stock-based compensation	**402**	529
Risk management (note 10)	**1,479**	1,474
Other	**102**	101
	3,093	3,178
Less: current portion	**1,707**	1,617
	$ 1,386	$ 1,561

Asset retirement obligations

At March 31, 2008, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $4,529 million (December 31, 2007 - $4,426 million). These costs will be incurred over the lives of the operating assets and have been discounted using a weighted average credit-adjusted risk free rate of 6.6% (December 31, 2007 - 6.6%). A reconciliation of the discounted asset retirement obligations is as follows:

	Three Months Ended Mar 31, 2008	Year Ended Dec 31, 2007
Balance – beginning of period	**$ 1,074**	$ 1,166
Liabilities incurred	**9**	21
Liabilities disposed	**-**	(65)
Liabilities settled	**(6)**	(71)
Asset retirement obligation accretion	**17**	70
Revision of estimates	**-**	35
Foreign exchange	**16**	(82)
Balance – end of period	**$ 1,110**	$ 1,074

Stock-based compensation

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

	Three Months Ended Mar 31, 2008	Year Ended Dec 31, 2007
Balance – beginning of period	$ 529	$ 744
Stock-based compensation	-	193
Payments for options surrendered	(80)	(375)
Transferred to common shares	(42)	(91)
(Recovery) capitalized to Horizon Project	(5)	58
Balance – end of period	402	529
Less: current portion	342	390
	$ 60	$ 139

5. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended	
	Mar 31 2008	Mar 31 2007
Current income tax – North America	$ 21	$ 25
Current income tax – North Sea	96	35
Current income tax – Offshore West Africa	38	10
Current income tax expense	155	70
Future income tax expense	80	100
Income tax expense	$ 235	$ 170

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 a future period. North America current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the nature, timing and amount of capital expenditures incurred in Canada in any particular year.

During the first quarter of 2008, enacted or substantively enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million in British Columbia and $22 million in Côte d'Ivoire, Offshore West Africa.

6. SHARE CAPITAL

Issued Common shares	Three Months Ended Mar 31, 2008 Number of shares (thousands)	Amount
Balance – beginning of period	**539,729**	**$ 2,674**
Issued upon exercise of stock options	**736**	**9**
Previously recognized liability on stock options exercised for common shares	**-**	**42**
Balance – end of period	**540,465**	**$ 2,725**

Normal Course Issuer Bid

The Company did not purchase any common shares for cancellation pursuant to the Normal Course Issuer Bid previously filed for the twelve month period beginning January 24, 2007 and ending January 23, 2008. The Company has not renewed the Normal Course Issuer Bid in 2008.

Dividend policy

In February 2008, the Board of Directors set the regular quarterly dividend at $0.10 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

	Three Months Ended Mar 31, 2008 Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of period	**30,659**	**$ 47.23**
Granted	**346**	**$ 72.14**
Surrendered for cash settlement	**(1,558)**	**$ 22.68**
Exercised for common shares	**(736)**	**$ 11.94**
Forfeited	**(876)**	**$ 53.35**
Outstanding – end of period	**27,835**	**$ 49.65**
Exercisable – end of period	**8,108**	**$ 34.27**

7. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	Three Months Ended **Mar 31 2008**	Mar 31 2007
Derivative financial instruments designated as cash flow hedges	**$ 108**	$ (31)
Foreign currency translation adjustment	**(13)**	(14)
	$ 95	$ (45)

8. CAPITAL DISCLOSURES

As required by Canadian generally accepted accounting principles (“GAAP”), effective January 1, 2008, 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 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 long-term debt divided by the sum of the carrying value of shareholders’ equity plus long-term debt. The Company aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the target range when cash flow from operating activities is greater than current investment activities. The ratio is currently at the high end of the target range due to the debt financing of a business acquisition in 2006 and the construction of 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.

	Mar 31 2008	Dec 31 2007
Long-term debt	**$ 11,230**	$ 10,940
Total shareholders’ equity	**$ 14,068**	$ 13,321
Debt to book capitalization	**44%**	45%

9. NET EARNINGS PER COMMON SHARE

	Three Months Ended	
	Mar 31 2008	Mar 31 2007
Weighted average common shares outstanding (thousands) – basic and diluted	**540,218**	538,890
Net earnings – basic and diluted	**$ 727**	$ 269
Net earnings per common share – basic and diluted	**$ 1.35**	$ 0.50

10. FINANCIAL INSTRUMENTS

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

	Mar 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	**1,615**	**-**	**-**
Accounts payable	**-**	**-**	**(455)**
Accrued liabilities	**-**	**-**	**(2,078)**
Risk management	**-**	**(1,479)**	**-**
Long-term debt	**-**	**-**	**(11,230)**
	$ 1,615	**$ (1,452)**	**$ (13,763)**

	Dec 31, 2007		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ -	$ 21	$ -
Accounts receivable	1,143	-	-
Accounts payable	-	-	(379)
Accrued liabilities	-	-	(1,567)
Risk management	-	(1,474)	-
Long-term debt	-	-	(10,940)
	$ 1,143	$ (1,453)	$ (12,886)

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

	Mar 31, 2008		Dec 31, 2007	
	Carrying value	**Fair value**	Carrying value	Fair value
Fixed-rate long-term debt (1)	**$ 7,706**	**$ 7,698**	$ 6,244	$ 6,259

(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 $41 million (2007 - $9 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 intended for trading or other 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:

	Three Months Ended Mar 31, 2008	Year Ended Dec 31, 2007
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market
Balance – beginning of period	**$ (1,474)**	$ 128
Retained earnings effect of adoption of financial instrument standards	**-**	14
Net cost of outstanding put options	**120**	58
Net change in fair value of outstanding derivative financial instruments attributable to:		
- Risk management activities	**(108)**	(1,400)
- Interest expense	**32**	9
- Foreign exchange	**75**	(350)
- Other comprehensive income	**(4)**	125
	(1,359)	(1,416)
Add: Put premium financing obligations (1)	**(120)**	(58)
Balance – end of period	**(1,479)**	(1,474)
Less: current portion	**(1,365)**	(1,227)
	$ (114)	$ (247)

(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 (liability) asset.

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

	Three Months Ended	
	Mar 31 2008	Mar 31 2007
Net realized risk management loss (gain)	**$ 416**	$ (88)
Net unrealized risk management loss	**108**	536
	$ 524	$ 448

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 price financial derivatives to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production. As at March 31, 2008, the Company had the following net financial derivatives outstanding to manage its commodity price exposures:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Apr 2008	–	Jun 2008	25,000 bbl/d	US$60.00	–	US$80.44	WTI
	Apr 2008	–	Sep 2008	25,000 bbl/d	US$60.00	–	US$80.46	WTI
	Jul 2008	–	Sep 2008	25,000 bbl/d	US$70.00	–	US$123.75	WTI
	Apr 2008	–	Dec 2008	20,000 bbl/d	US$50.00	–	US$65.53	Mayan Heavy
	Apr 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$75.22	WTI
	Apr 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.05	WTI
	Apr 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.98	WTI
	Oct 2008	–	Dec 2008	25,000 bbl/d	US$70.00	–	US$112.63	WTI
	Jan 2009	–	Dec 2009	25,000 bbl/d	US$70.00	–	US$111.56	WTI
Crude oil puts	Apr 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
	Jan 2009	–	Dec 2009	50,000 bbl/d			US$80.00	WTI

The net cost of outstanding put options and their respective periods of settlement are as follows:

	Q2 2008	Q3 2008	Q4 2008	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Cost ($ millions)	US$15	US$15	US$15	US$18	US$18	US$18	US$18

	Remaining term			Volume	Weighted average price			Index
Natural gas								
AECO price collars	Apr 2008	–	Sep 2008	290,000 GJ/d	C$7.50	–	C$8.69	AECO

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

Interest rate risk

The Company is exposed to interest rate risk on its fixed and floating rate long-term debt. The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At March 31, 2008, the Company had the following interest rate swap contracts outstanding:

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Apr 2008	–	Oct 2012	US$350	5.45%	LIBOR (1) + 0.81%
	Apr 2008	–	Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%

(1) London Interbank Offered Rate

All interest rate related derivative financial instruments designated as hedges at March 31, 2008 were classified as fair value hedges.

Foreign currency exchange rate risk

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated debt. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in foreign currencies in its foreign subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company enters into cross currency swap agreements to manage currency exposure on US dollar denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At March 31, 2008, 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	Apr 2008	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Apr 2008	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Apr 2008	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency related derivative financial instruments designated as hedges at March 31, 2008 were classified as cash flow hedges.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at March 31, 2008 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	$ (42)	$ -
Decrease WTI US$1.00/bbl	$ 42	$ -
Increase AECO C$0.10/mcf	$ (2)	$ -
Decrease AECO C$0.10/mcf	$ 2	$ -
Interest rate risk		
Increase interest rate 1%	$ (19)	$ 13
Decrease interest rate 1%	$ 19	$ (15)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (28)	$ -
Decrease exchange rate by US$0.01	$ 28	$ -

b) Credit risk

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

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. Substantially all of the Company's accounts receivables are 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 substantially all investment grade financial institutions and other entities. At March 31, 2008, the Company had net risk management assets of $6 million with specific counterparties related to derivative financial instruments (December 31, 2007 - $20 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 maintains 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	$	455	$	-	$	-	$	-
Accrued liabilities	$	2,078	$	-	$	-	$	-
Risk management	$	1,362	$	11	$	(40)	$	146
Long-term debt (1)	$	40	$	2,374	$	1,982	$	5,694

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,182 million of revolving bank credit facilities due to the extendable nature of the facilities.

11. COMMITMENTS

The Company has committed to certain payments as follows:

		Remaining 2008		2009		2010		2011		2012		Thereafter
Product transportation and pipeline	$	180	$	163	$	149	$	123	$	107	$	1,099
Offshore equipment operating leases (1)	$	98	$	130	$	118	$	116	$	94	$	405
Offshore drilling (2) (3)	$	274	$	187	$	47	$	-	$	-	$	-
Asset retirement obligations (4)	$	28	$	4	$	5	$	4	$	4	$	4,484
Office leases	$	19	$	26	$	29	$	22	$	2	$	-
Electricity and other	$	126	$	267	$	162	$	4	$	-	$	-

(1) Offshore equipment operating leases are primarily comprised of obligations related to floating production, storage and offtake vessels ("FPSO"). During 2006, the Company entered into an agreement to lease an additional FPSO commencing in 2008, in connection with the planned offshore development in Gabon, Offshore West Africa. During the initial term, the total annual payments for the Gabon FPSO are estimated to be US$50 million.

(2) During 2007, the Company entered into a one-year agreement for offshore drilling services related to the Baobab Field in Côte d'Ivoire, Offshore West Africa. The agreement is scheduled to commence in the second quarter of 2008, on delivery of the rig. Estimated total payments of US$100 million, after joint venture recoveries, have been included in this table for the period 2008 - 2009.

(3) During 2007, the Company awarded contracts for a drilling rig and for the construction of wellhead towers in connection with the planned offshore development in Gabon, Offshore West Africa. Estimated total payments of US$392 million have been included in this table for the period 2008 - 2010.

(4) 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 2008 - 2012 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

In addition to the amounts disclosed above, the Company has budgeted construction costs of approximately $1.1 billion to $1.3 billion for the remainder of 2008 related to the planned completion of Phase 1 of the Horizon Project.

12. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America Three Months Ended Mar 31		North Sea Three Months Ended Mar 31		Offshore West Africa Three Months Ended Mar 31	
	2008	2007	**2008**	2007	2008	2007
Segmented revenue	**3,215**	2,535	**508**	431	**237**	144
Less: royalties	**(405)**	(366)	**(1)**	(1)	**(43)**	(9)
Segmented revenue, net of royalties	**2,810**	2,169	**507**	430	**194**	135
Segmented expenses						
Production	**451**	422	**112**	116	**21**	22
Transportation and blending	**493**	365	**3**	4	**-**	-
Depletion, depreciation and amortization	**566**	560	**86**	107	**34**	40
Asset retirement obligation accretion	**11**	9	**6**	8	**-**	1
Realized risk management loss (gain)	**417**	(92)	**(1)**	4	**-**	-
Total segmented expenses	**1,938**	1,264	**206**	239	**55**	63
Segmented earnings before the following	**872**	905	**301**	191	**139**	72
Non-segmented expenses						
Administration						
Stock-based compensation expense						
Interest, net						
Unrealized risk management loss						
Foreign exchange loss (gain)						
Total non-segmented expenses						
Earnings before taxes						
Taxes other than income tax						
Current income tax expense						
Future income tax expense						
Net earnings						

(millions of Canadian dollars, unaudited)	Midstream Three Months Ended Mar 31 2008	 2007	Inter-segment elimination and other Three Months Ended Mar 31 2008	 2007	Total Three Months Ended Mar 31 2008	 2007
Segmented revenue	**20**	19	**(13)**	(11)	**3,967**	3,118
Less: royalties	**-**	-	**-**	-	**(449)**	(376)
Segmented revenue, net of royalties	**20**	19	**(13)**	(11)	**3,518**	2,742
Segmented expenses						
Production	**5**	6	**(2)**	(1)	**587**	565
Transportation and blending	**-**	-	**(11)**	(10)	**485**	359
Depletion, depreciation and amortization	**2**	2	**-**	-	**688**	709
Asset retirement obligation accretion	**-**	-	**-**	-	**17**	18
Realized risk management loss (gain)	**-**	-	**-**	-	**416**	(88)
Total segmented expenses	**7**	8	**(13)**	(11)	**2,193**	1,563
Segmented earnings before the following	**13**	11	**-**	-	**1,325**	1,179
Non-segmented expenses						
Administration					**43**	60
Stock-based compensation expense					**-**	25
Interest, net					**49**	83
Unrealized risk management loss					**108**	536
Foreign exchange loss (gain)					**114**	(27)
Total non-segmented expenses					**314**	677
Earnings before taxes					**1,011**	502
Taxes other than income tax					**49**	63
Current income tax expense					**155**	70
Future income tax expense					**80**	100
Net earnings					**727**	269

Net additions to property, plant and equipment

	Three Months Ended					
	Mar 31, 2008			Mar 31, 2007		
	Net Expenditures	**Non Cash/Fair Value Changes (1)**	**Capitalized Costs**	Net Expenditures	Non Cash/Fair Value Changes (1)	Capitalized Costs
North America	**$ 663**	**$ 9**	**$ 672**	$ 998	$ 5	$ 1,003
North Sea	**45**	**-**	**45**	138	-	138
Offshore West Africa	**94**	**(1)**	**93**	36	-	36
Other	**-**	**-**	**-**	1	-	1
Horizon Project (2)	**941**	**-**	**941**	809	-	809
Midstream	**1**	**-**	**1**	2	-	2
Head office	**3**	**-**	**3**	5	-	5
	$ 1,747	**$ 8**	**$ 1,755**	$ 1,989	$ 5	$ 1,994

(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 Horizon Project also include capitalized interest and stock-based compensation.

	Property, plant and equipment		Total assets	
	Mar 31 2008	Dec 31 2007	**Mar 31 2008**	Dec 31 2007
Segmented assets				
North America	**$ 22,143**	$ 22,033	**$ 24,172**	$ 23,617
North Sea	**1,774**	1,728	**2,063**	1,957
Offshore West Africa	**1,244**	1,188	**1,387**	1,354
Other	**25**	25	**50**	41
Horizon Project	**9,592**	8,651	**9,662**	8,740
Midstream	**204**	205	**352**	333
Head office	**69**	72	**69**	72
	$ 35,051	$ 33,902	**$ 37,755**	$ 36,114

Capitalized interest

The Company capitalizes construction period interest based on Horizon Project costs incurred and the Company's cost of borrowing. Interest capitalization on a particular development phase ceases once construction is substantially complete and this phase of the Horizon Project is available for its intended use. For the three months ended March 31, 2007, pre-tax interest of $111 million was capitalized to the Horizon Project (March 31, 2007 - $71 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 March 31, 2008:	
Interest coverage (times)	
Net earnings [1]	5.2x
Cash flow from operations [2]	11.0x

(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.

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CORPORATE INFORMATION

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Vice-Chairman of the Board

John G. Langille*
Vice-Chairman of the Board

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*Management Committee

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ

New York Stock Exchange
Trading Symbol – CNQ

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