Canadian Natural

News Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES
RECORD FIRST QUARTER CASH FLOW AND NATURAL GAS PRODUCTION VOLUMES
CALGARY, ALBERTA – MAY 3, 2007 – FOR IMMEDIATE RELEASE

In commenting on first quarter 2007 results, Canadian Natural's Chairman, Allan Markin stated, "It was a very successful quarter yielding strong crude oil and natural gas production volumes. We completed the integration of the Anadarko Canada assets with their performance overall better than expected. Through focused execution we have been able to maximize the efforts of our winter natural gas drilling program. A reduced program from first quarter of 2006 levels allowed us to concentrate on operational efficiencies and we were able to maximize the value of every dollar spent. The result was production at the top end of our first quarter guidance generated with capital expenditures within our original targets. This capital discipline is being maintained throughout our organization and is exemplified through the winter drilling program as well as continued cost controls at the Horizon Oil Sands Project."

Further comment from John Langille, Vice Chairman, included, "The successful drilling program and volumetric growth enabled us to generate record cash flows in Q1/07. We expect that our conventional business will generate 2007 cash flows of $6.0 to $6.5 billion based upon today's strip pricing. After conventional capital requirements of $3.1 billion, the conventional business is generating free cash flow of approximately $3 billion. In 2007, a large portion of that free cash flow is being directed toward construction costs at the Horizon Project which remains on target for first oil for the third quarter of 2008. We are continuing to deliver on our defined plan, and the cash flow potential of our businesses should be more than sufficient to fund the plan."

Steve Laut, President and Chief Operating Officer of Canadian Natural added, "The execution of our defined plan is a dynamic one, based upon maximizing shareholder value. Reflecting this principal, during the first quarter we made the strategic decision to reduce natural gas drilling in favor of higher return heavy oil projects. Similarly, we made the strategic decision to defer further work on a second heavy oil upgrader to handle our in-situ production growth pending stability in construction costs and clarification on how various government initiatives will be implemented. The acceleration of re-drilling at Baobab, where a portion of our 2008 capital budget will now be directed to accommodate the recent availability of a deepwater drilling rig, is another example. In essence, we retain flexibility in our ongoing programs such that capital allocation for projects is continually high-graded."

HIGHLIGHTS

($ millions, except as noted)	Three Months Ended **Mar 31 2007**	Dec 31 2006	Mar 31 2006
Net earnings	**$ 269**	$ 313	$ 57
per common share, basic and diluted	**$ 0.50**	$ 0.58	$ 0.11
Adjusted net earnings from operations (1)	**$ 621**	$ 412	$ 268
per common share, basic and diluted	**$ 1.15**	$ 0.77	$ 0.50
Cash flow from operations (2)	**$ 1,622**	$ 1,293	$ 1,039
per common share, basic and diluted	**$ 3.01**	$ 2.41	$ 1.93
Capital expenditures, net of dispositions	**$ 2,009**	$ 6,497	$ 2,309
Daily production, before royalties			
Natural gas (mmcf/d)	**1,717**	1,620	1,436
Crude oil and NGLs (bbl/d)	**327,001**	343,705	323,662
Equivalent production (boe/d)	**613,114**	613,764	563,027

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

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

- Natural gas production volumes reached record levels and represented 47% of the Company's total production. Natural gas production for Q1/07 averaged 1,717 mmcf/d compared to 1,436 mmcf/d for Q1/06 and 1,620 mmcf/d for Q4/06. The increase in natural gas production from the comparable periods primarily reflected a full quarter of additional natural gas production from the Anadarko Canada Corporation ("ACC") acquisition completed in November 2006 along with a very successful natural gas winter drilling program.

- Total crude oil and NGLs production of 327,001 bbl/d was comparable to 323,662 bbl/d for Q1/06, and decreased 5% from 343,705 bbl/d for Q4/06. The decrease from the prior quarter was anticipated due to the timing of steaming cycles related to the Company's thermal crude oil projects in North America and planned maintenance activities at the Espoir Field.

- Quarterly cash flow of $1.6 billion, an increase of 25% from Q4/06 and 56% from Q1/06. The increase from Q1/06 reflects the impact of increased crude oil pricing related to a narrower heavy crude oil differential from WTI, increased natural gas sales volumes, decreased realized risk management losses, and a slightly weaker Canadian dollar relative to the US dollar.

- Quarterly net earnings of $269 million, representing a 14% decrease from Q4/06 and a 372% increase from Q1/06. Net earnings in Q1/07 included unrealized after-tax expenses of $352 million related to the effects of risk management activities, foreign exchange gains, stock-based compensation expense, and statutory tax rate changes on future income tax liabilities.

- Quarterly adjusted net earnings from operations of $621 million, 51% higher than Q4/06 results and a 132% increase from Q1/06, reflecting stronger cash flow.

- Completed a Q1/07 drilling program of 193 net crude oil wells and 201 net natural gas wells, excluding stratigraphic test and service wells, with an 87% success ratio. The success rate is a reflection of Canadian Natural's strong, predictable, low-risk asset base. Crude oil drilling increased 110%, compared to Q1/06. Natural gas drilling decreased by 54% compared to Q1/06, representing Canadian Natural's reallocation of capital towards a higher return crude oil drilling program and reduced natural gas drilling program.

- Maintained a strong undeveloped conventional core land base in Canada of 12.4 million net acres - a key asset in today's highly competitive industry.

- The Horizon Oil Sands Project ("Horizon Project") exited Q1/07 ahead of schedule at 66% complete, with approximately $5.3 billion in purchase orders and contracts having been awarded to date.

- Continued production improvements at the Pelican Lake Field from new drilling activity and the expansion of the enhanced crude oil recovery program. Pelican Lake crude oil production averaged approximately 32,000 bbl/d during the quarter, up 10% or approximately 3,000 bbl/d from Q1/06. Production is expected to continue to increase in Q2/07 and throughout the remainder of 2007.

- Secured a deep water drilling rig for the Baobab Field. The equipment will be mobilized in late 2007 or early 2008, enabling shut-in production to come back on-line over the course of 2008.

- Completed the issuance of US$1,100 million principal amount of 5.70% unsecured notes due May 2017 and US$1,100 million principal amount of 6.25% unsecured notes due March 2038. Concurrently, the Company entered into cross currency interest rate swaps to fix the Canadian dollar interest and principal repayment amounts on US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million. The Company also entered into a cross currency interest rate swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million.

- Declared a quarterly cash dividend on common shares of C$0.085 per common share, payable April 1, 2007, a 13% increase over the 2006 quarterly dividend. This is the sixth consecutive annual increase.

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, 2007 (thousands of net acres)	**Drilling activity three months ended Mar 31, 2007 (net wells)**
Canadian conventional		
Northeast British Columbia	**2,607**	**50**
Northwest Alberta	**1,587**	**83**
Northern Plains	**6,759**	**280**
Southern Plains	**927**	**27**
Southeast Saskatchewan	**135**	**8**
In-situ Oil Sands	**407**	**139**
	12,422	**587**
Horizon Oil Sands Project	**116**	**98**
United Kingdom North Sea	**298**	**2**
Offshore West Africa	**206**	**1**
	13,042	**688**

Drilling activity (number of wells)

	Three Months Ended Mar 31			
	2007		2006	
	Gross	**Net**	Gross	Net
Crude oil	**210**	**193**	106	92
Natural gas	**246**	**201**	537	440
Dry	**68**	**60**	65	61
Subtotal	**524**	**454**	708	593
Stratigraphic test / service wells	**234**	**234**	297	297
Total	**758**	**688**	1,005	890
Success rate (excluding stratigraphic test / service wells)		**87%**		90%

North America Conventional

North America natural gas	Quarterly Results		
	Q1/07	Q4/06	Q1/06
Natural gas production (mmcf/d)	**1,694**	1,594	1,411
Net wells targeting natural gas	**245**	74	499
Net successful wells drilled	**201**	60	440
Success rate	**82%**	81%	88%

- Q1/07 production increased 20% over Q1/06 and increased 6% over Q4/06. These increases reflect full quarter inclusion of ACC production along with a successful winter drilling program.

- Canadian Natural drilled 201 net successful natural gas wells in Q1/07 compared to 440 net natural gas wells in Q1/06, which represents a 54% reduction. High drilling success rates reflect Canadian Natural's low-risk exploitation approach and high quality land base. The Q1/07 natural gas drilling program represented an active program across the Company's core regions. In Northeast British Columbia 49 net wells were drilled, while in Northwest Alberta 78 net wells were drilled. In the Northern Plains, 92 net wells were drilled, with 26 net wells drilled in the Southern Plains.

- Planned drilling activity for Q2/07 includes 13 natural gas wells compared to drilling activity for Q2/06 of 48 natural gas wells. This is a reflection of the Company's decision to proactively reduce exposure to over-inflated service and supply costs, along with the seasonality of natural gas drilling.

- Although third party service costs have not decreased significantly, Canadian Natural has experienced productivity gains as a result of the focused drilling program.

North America crude oil and NGLs	Quarterly Results		
	Q1/07	Q4/06	Q1/06
Crude oil and NGLs production (bbl/d)	**237,489**	249,565	222,955
Net wells targeting crude oil	**207**	188	90
Net successful wells drilled	**191**	174	88
Success rate	**92%**	93%	98%

- Q1/07 North America crude oil and NGLs production decreased 5% from Q4/06 and increased 7% over Q1/06. Pelican Lake experienced strong performance and continued production improvements that offset the decrease in Q1/07 that was largely a result of the timing of the normal steaming cycle in thermal crude oil production.

- During Q1/07, drilling activity included 144 net wells targeting heavy crude oil, 36 net wells targeting Pelican Lake crude oil, 9 net wells targeting thermal crude oil and 18 net wells targeting light crude oil. The majority of the wells were drilled in the Northern Plains core region.

- The Primrose East expansion program continues with a planned expansion of the crude oil processing facility from 80,000 bbl/d to 120,000 bbl/d, as well as the construction of a steam generation plant and new pad drilling targeted to add production gains of 40,000 bbl/d in 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. Detailed engineering, procurement and site clearing are underway.

- At Pelican Lake, the development and secondary recovery implementation projects continued as planned with 36 horizontal producing wells drilled in Q1/07 and 96 additional horizontal wells planned for the remainder 2007. In addition, 30 production wells were converted to injection wells (9 for water injection and 21 for polymer injection) in Q1/07. Results from the polymer flood continue to be positive and 2 additional polymer skids were installed in Q1/07. The program continues to be optimized and the results will be monitored.

- Planned drilling activity for Q2/07 includes 86 net crude oil wells, excluding stratigraphic test and service wells.

- In early 2007, Canadian Natural issued its proposed development plan for the 30,000 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 is targeting to file its formal regulatory application documents for this project in the latter half of 2007 pending the results of potential changes to royalty regimes and environmental regulations, and the associated costs resulting there from.

Anticipated Changes to Legislation

- The Alberta provincial government is currently reviewing its crude oil and natural gas royalty regime. It is too early to predict the outcome of this review.

- The Federal and Provincial governments are in the process of drafting policy and legislation to control greenhouse gas emissions. Operating in the high cost and highly regulated environment of the Western Canadian Sedimentary Basin ("WCSB"), additional cost requirements as a result of greenhouse gas legislation will add to the challenge of executing projects within the WCSB.

International

The Company operates in the North Sea and Offshore West Africa where production of lighter quality crude oil is targeted in conjunction with natural gas that may be produced in association with crude oil production.

	Quarterly Results		
	Q1/07	Q4/06	Q1/06
Crude oil production (bbl/d)			
North Sea	**61,869**	61,786	60,802
Offshore West Africa	**27,643**	32,354	39,905
Natural gas production (mmcf/d)			
North Sea	**15**	16	17
Offshore West Africa	**8**	10	8
Net wells targeting crude oil	**2.8**	2.3	4.2
Net successful wells drilled	**2.8**	2.3	4.2
Success rate	**100%**	100%	100%

North Sea

- Canadian Natural continues to execute its exploitation strategy in the North Sea. The first stage of this exploitation program is based upon optimizing existing facilities and waterfloods. Canadian Natural continues to apply this first stage of exploitation on its holdings in the North Sea. The second stage of exploitation incorporates more near pool development and exploration in order to maximize utilization of the common facilities and ultimately extend all fields' economic lives. Ongoing development at the Columba Terraces and the Lyell Field are examples of this type of work.

- In Q1/07, 1.6 net wells were drilled, with an additional 2.8 net wells drilling at the end of the quarter.

- The development of the Lyell Field continued during the first quarter. Tranche 1 of the Lyell Field development comprises two production wells scheduled for completion during 2007, and an additional 2 production wells and 2 well workovers in 2008.

- Construction of the Columba E Raw Water Injection facilities continued during the quarter. Commissioning is scheduled for Q2/07 at which time water injection wells are due to be completed, with production expected to reach full capacity by 2008.

Offshore West Africa

- During Q1/07, 1.2 net wells were drilled with 0.6 additional net wells drilling at the end of the quarter.

- First oil from West Espoir commenced in 2006 with 3 production wells and 2 injector wells. During Q1/07, 1 additional production well was added. The West Espoir area development drilling will continue until 2008 with producers and injectors being brought on-line as they are completed.

- A deepwater drilling rig has been secured for the Baobab Field. The rig will be mobilized in late 2007 or early 2008, which will enable the Company's shut-in production to be brought back on stream.

- At the 90% owned and operated field in offshore Gabon, activity continued with contracts awarded for the construction of the wellhead towers and for a drilling rig. Drilling is scheduled to commence in Q2/08 and first crude oil is targeted for late 2008. Production is forecasted to plateau at approximately 20,000 bbl/d.

Horizon Project

- Phase 1 of the Horizon Project continues on schedule with first production of 110,000 bbl/d of light, sweet SCO targeted to commence in Q3/08.

- The progress on major milestones, a key component in achieving critical path success, is slightly ahead of schedule.

- During Q1/07, the Company awarded a further $131 million of contracts, including several that were previously deferred in order to optimize pricing. This brings the total awarded contracts to $5.3 billion. To date, all major plants have been through hazard/operability engineering review without requiring major scope change, providing even greater cost certainty. The construction is at a point where the critical foundations are complete, steel is being erected, modules are being placed and equipment is being set.

- Canadian Natural continues to effectively execute its well defined strategies. Overall work progress at the end of Q1/07 (engineering, procurement and construction) was at 66% complete. Field construction itself is over 52% complete. All major vessels have either been erected or are currently on-site as work moves forward into the most labour-intensive portion of the Horizon Project. Work scheduled for the coming months will focus more on mechanical construction efforts, which are scheduled to be completed through a mix of lump sum and reimbursable contracts.

- The Company has now entered into the majority of the construction contracts and as the final 34% of the overall project is undertaken, the aforementioned challenges are causing cost estimates for certain isolated pieces of the project to increase above targeted cost. Our actual spending to date is near plan (69% actual versus 68% plan) and our overall project forecast cost is currently forecasted in a range that is not materially in excess from that approved by the Board of Directors in February 2005, positioning Canadian Natural favorably given the rise in costs that has occurred during the last two years. Our current project completion cost forecast ranges from approximately 5% to 12% over the original $6.8 billion estimate.

- The quarterly update for Phase 1 of the Horizon Project is as follows:

Project status summary	**Mar 31, 2007**		Jun 30, 2007
	Actual	Plan	Plan
Phase 1 - Work progress (cumulative)	**66%**	65%	77%
Phase 1 - Construction capital spending (cumulative)*	**69%**	68%	77%

** Relates to overall Phase 1 construction capital of $6.8 billion.*

Accomplished during the First Quarter of 2007

Detailed Engineering

- Overall detailed engineering 96% complete and substantially complete in most areas.

Procurement

- Overall procurement progress is 91% complete.
- Awarded over $5.3 billion in purchase orders and contracts to date.
- Operations and maintenance service and supply agreements in negotiation.

Modularization

- Delivered an additional 279 oversized loads to site for a total of 1,252 loads, which represents approximately 76% of the total requirement.

Construction

- Overall construction progress is 52% complete.
- Mine overburden removal has moved 32 million bank cubic meters, which represents approximately 46% of the total to be moved and is 4% ahead of schedule.
- 2006/2007 drilling program completed.
- Began installing the Heat Recovery Steam Generator.
- Moved crushing plant assemblies for Ore Preparation plant from the pre-assemble area to the permanent foundations.
- Commenced module setting in the Hydrotreater Area.
- Primary Separation Cell ready for hydrotesting.
- High pressure natural gas piping ready for commissioning.

- Completed module fabrication and installation for coker and diluent recovery unit.
- Completed cooling tower erection.
- Finished installation of the last remaining 35kV substation.

Milestones for the Second Quarter of 2007

- Complete installation of coker and diluent recovery unit process structures.
- Complete Primary Upgrading interconnecting welding on piperacks.
- Energize main electrical substations R1/R2.
- Mechanically complete cooling tower piping.
- 42" water pipeline to be complete and tested.
- Water pumphouses mechanically complete.

Phase 2/3 Update

- Originally commenced in mid 2006, Canadian Natural continues to proceed forward with Phase 2/3 of the Horizon Project with significant progress made towards the EDS portion of front end engineering. To date, Canadian Natural has spent approximately $124 million on Phase 2/3, with $203 million budgeted for 2007 for these phases.
- In 2006, Canadian Natural ordered certain major vessels required for Phase 2/3 of the Horizon Project, including the coke drums and the hydrotreating vessels. To date, coker foundations have been built, together with the construction of significant piperack and common service infrastructure. The engineering and construction work that has been completed provides Canadian Natural a distinct and strategic advantage over other projects as Canadian Natural builds the Horizon Project. Canadian Natural is currently evaluating several execution options for the balance of Phase 2/3 construction that will provide flexibility and balance the risks associated with building in the current high cost environment.

Operations Readiness

- Canadian Natural has had operations staff involved in the design, procurement and construction of the Horizon Project from project commencement. Canadian Natural believes this has resulted in a design that will be less difficult to commission and start-up had there been no operations staff involved. The operations staff is responsible for the commissioning and start-up of the facilities and have already prepared a commissioning and start-up schedule which is directly linked to the construction schedule. This allows the project team to identify challenges early on and ensure that adequate contingency plans are in place.
- Currently there are 142 operations staff employed in the development of start-up procedures, preparation of training programs, recruitment of additional staff, establishment of maintenance programs and operation of several plant systems.
- The operations staff has had the opportunity to test-run many programs through the early operation of plant systems. The team is currently operating some mine equipment and several plant facilities such as water treatment, sewage treatment, communications, natural gas and power distribution. As a result, the team has already developed several early learnings that have been incorporated into later start-up plans.
- Throughout 2007, increasing focus will be placed upon commissioning and start-up as operations staff levels increase and procedures are optimized.

MARKETING

	Quarterly Results		
	Q1/07	Q4/06	Q1/06
Crude oil and NGLs pricing			
WTI [1] benchmark price (US$/bbl)	**$ 58.23**	$ 60.21	$ 63.53
Lloyd Blend Heavy oil differential from WTI (%)	**27%**	35%	45%
Corporate average pricing before risk management (C$/bbl)	**$ 51.71**	$ 47.27	$ 43.79
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 7.07**	$ 6.03	$ 8.82
Corporate average pricing before risk management (C$/mcf)	**$ 7.74**	$ 6.66	$ 8.30

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

- In Q1/07, the Company experienced a narrowing of the heavy oil differential to under 30%, well below seasonal expectations and favorable compared to Q1/06. Canadian Natural has committed to 25,000 bbl/d of pipeline capacity on the Pegasus Pipeline, which transports Company volumes to the U.S. Gulf Coast, as part of the Company's efforts towards working with various industry groups to find new markets for Western Canadian heavy crude oil.

- During Q1/07, the Company contributed approximately 135,000 bbl/d of its heavy crude oil streams to the Western Canadian Select ("WCS") blend as market conditions resulted in this strategy offering the optimal pricing for bitumen.

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 its strengths are:

  – A diverse asset base geographically and by product - produced in excess of 613,000 boe/d in Q1/07, comprised of approximately 47% natural gas and 53% crude oil - with 95% of production located in G7 countries with stable and secure economies.

  – Financial stability and liquidity – approximately $6.3 billion of bank credit facilities, with an aggregate $1.6 billion of unused bank lines available at March 31, 2007.
- Completed the issuance of US$1,100 million principal amount of 5.70% unsecured notes due May 2017 and US$1,100 million principal amount of 6.25% unsecured notes due March 2038, which have been sold to investors in the United States. The 5.70% unsecured notes were sold at a price of 99.725% per note to yield 5.734% to maturity. The 6.25% unsecured notes were sold at a price of 99.323% per note to yield 6.30% to maturity. Net proceeds from the sale were used to repay bank indebtedness. Concurrently, the Company entered into cross currency interest rate swaps to fix the Canadian dollar interest and principal repayment amounts on US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million. The Company also entered into a cross currency interest rate swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million.
- Declared a quarterly cash dividend on common shares of C$0.085 per common share, payable April 1, 2007, a 13% increase over the 2006 quarterly dividend. This is the sixth consecutive annual increase.

OUTLOOK

The Company forecasts 2007 production levels before royalties to average between 1,594 and 1,664 mmcf/d of natural gas and between 315 and 360 mbbl/d of crude oil and NGLs. Q2/07 production guidance before royalties is forecast to average between 1,677 and 1,698 mmcf/d of natural gas and between 313 and 329 mbbl/d of crude oil and NGLs. Detailed guidance on revised 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 for Canadian Natural Resources Limited (the "Company") may constitute "forward-looking statements" within the meaning of the United States Private Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as the Company "believes", "anticipates", "expects", "plans", "estimates", "targets", or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, 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; foreign currency exchange rates; 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; availability and cost of seismic, drilling and other equipment; ability of the Company to complete its capital programs; ability of the Company to transport its products to market; 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 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; success of exploration and development activities; timing and success of integrating the business and operations of acquired companies; production levels; uncertainty of reserve estimates; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); asset retirement obligations; and other circumstances affecting revenues and expenses. 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.

Disclosure related to future commodity pricing, production volumes, royalties, capital expenditures and other 2007 guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitutes forward looking statements as described above.

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.

Readers are cautioned that the foregoing list of important factors is not exhaustive. 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, 2007 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2006.

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.

Certain figures related to the presentation of gross revenues and gross transportation and blending provided for the three months ended March 31, 2006 have been reclassified to conform to the presentation adopted in the fourth quarter of 2006.

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, 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, 2007 in relation to the three months ended March 31, 2006 and the prior quarter. The accompanying tables form an integral part of this MD&A. This MD&A is dated May 2, 2007. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2006, is available on SEDAR at www.sedar.com.

FINANCIAL HIGHLIGHTS
($ millions, except per common share amounts)

	Three Months Ended		
	Mar 31 2007	Dec 31 2006	Mar 31 2006 (1)
Revenue, before royalties	**$ 3,118**	$ 2,826	$ 2,668
Net earnings	**$ 269**	$ 313	$ 57
Per common share – basic and diluted	**$ 0.50**	$ 0.58	$ 0.11
Adjusted net earnings from operations (2)	**$ 621**	$ 412	$ 268
Per common share – basic and diluted	**$ 1.15**	$ 0.77	$ 0.50
Cash flow from operations (3)	**$ 1,622**	$ 1,293	$ 1,039
Per common share – basic and diluted	**$ 3.01**	$ 2.41	$ 1.93
Capital expenditures, net of dispositions	**$ 2,009**	$ 6,497	$ 2,309

(1) Blending costs that were netted against gross revenues in prior periods have been reclassified to transportation expense to conform to the presentation adopted in the fourth quarter of 2006.

(2) Adjusted net earnings from operations is a non-GAAP term 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 following reconciliation 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.

	Three Months Ended		
($ millions)	***Mar 31 2007***	*Dec 31 2006*	*Mar 31 2006*
Net earnings as reported	***$ 269***	*$ 313*	*$ 57*
Stock-based compensation expense, net of tax (a)	***17***	*120*	*88*
Unrealized risk management loss (gain), net of tax (b)	***362***	*(158)*	*5*
Unrealized foreign exchange (gain) loss, net of tax (c)	***(27)***	*137*	*8*
Effect of statutory tax rate changes on future income tax liabilities (d)	***-***	*-*	*110*
Adjusted net earnings from operations	***$ 621***	*$ 412*	*$ 268*

(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, net of taxes, flow through net earnings, or are capitalized to the Horizon Oil Sands Project.

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

(d) All substantively enacted adjustments in applicable income tax rates are applied to underlying assets and liabilities on the Company's balance sheet in determining future income tax assets and liabilities. The impact of these tax rate changes is recorded in net earnings during the period the legislation is substantively enacted. Income tax rate changes in the first quarter of 2006 resulted in an increase of future income tax liabilities of approximately $110 million in the UK North Sea.

(3) *Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. 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. Cash flow from operations may not be comparable to similar measures presented by other companies.*

	Three Months Ended		
($ millions)	***Mar 31 2007***	*Dec 31 2006*	*Mar 31 2006*
Net earnings	***$ 269***	*$ 313*	*$ 57*
Non-cash items:			
Depletion, depreciation and amortization	***709***	*724*	*521*
Asset retirement obligation accretion	***18***	*18*	*17*
Stock-based compensation expense	***25***	*176*	*132*
Unrealized risk management loss (gain)	***536***	*(231)*	*8*
Unrealized foreign exchange (gain) loss	***(32)***	*161*	*10*
Deferred petroleum revenue tax (recovery) expense	***(3)***	*(3)*	*26*
Future income tax expense	***100***	*135*	*268*
Cash flow from operations	***$ 1,622***	*$ 1,293*	*$ 1,039*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings in the first quarter of 2007 were $269 million compared to net earnings of $57 million in the first quarter of 2006 and net earnings of $313 million in the prior quarter. Net earnings in the first quarter of 2007 included unrealized after-tax expenses of $352 million related to the effects of risk management activities, fluctuations in foreign exchange rates, stock-based compensation expense and statutory tax rate changes on future income tax liabilities, compared to net after-tax expenses of $211 million for the first quarter of 2006 and $99 million of after-tax expenses in the prior quarter. Excluding these items, adjusted net earnings from operations in first quarter 2007 increased to $621 million from $268 million in the first quarter of 2006, and increased from $412 million in the prior quarter. The increase from the first quarter of 2006 was primarily due to the impact of increased crude oil pricing related to a narrower Heavy Crude Oil Differential from WTI ("Heavy Differential"), higher sales volumes, decreased realized risk management losses, and a slightly weaker Canadian dollar relative to the US dollar. These factors were partially offset by decreased natural gas pricing, increased production expense and increased depletion, depreciation and amortization expense. The increase from the prior quarter was primarily due to increased crude oil pricing related to a narrower Heavy Differential, increased natural gas pricing, increased natural gas sales volumes, decreased realized risk management losses on crude oil, and the impact of a slightly weaker Canadian dollar relative to the US dollar, partially offset by decreased crude oil and NGLs 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 expenditure program throughout the Horizon Oil Sands Project ("Horizon Project") construction period. This program 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 crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 60% of expected crude oil volumes and approximately 70% of expected natural gas volumes are hedged for the remainder of 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by put options for the remainder of 2007 at a strike price of US$60.00 per barrel.

In addition, the Company has hedged 200,000 bbl/d of crude oil volumes for the year 2008. Of the 200,000 bbl/d, 150,000 bbl/d are hedged by price collars with a US$60.00 floor and 50,000 bbl/d are hedged by put options with a US$55.00 strike price. Subsequent to March 31, 2007, the Company entered into an additional 50,000 bbl/d of price collars with a US$60.00 floor for the first quarter of 2008. In addition, 900,000 GJ/d of natural gas volumes are hedged by price collars for the first quarter of 2008; 400,000 GJ/d with a $7.00 floor and 500,000 GJ/d with a $7.50 floor.

As disclosed in note 2 to the Company's unaudited interim consolidated financial statements as at March 31, 2007, commencing January 1, 2007, all derivative financial instruments are now recognized at fair value on the consolidated balance sheet at each balance sheet date. As effective as the Company's hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The change in the fair value of the 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, 2007.

Due to the changes in crude oil and natural gas forward pricing and the reversal of prior-year unrealized gains, the Company recorded a net unrealized loss of $536 million ($362 million after-tax) on its commodity risk management activities for the first quarter of 2007. 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 and does not intend to alter its current strategy of obtaining price certainty for its crude oil and natural gas sales. For further details, refer to Risk Management Activities on page 30 of this MD&A.

The Company also recorded a $25 million ($17 million after-tax) stock-based compensation expense as a result of the 3% increase in the Company's share price in the first quarter of 2007 (Company's share price as at: March 31, 2007 – C$63.75; December 31, 2006 - C$62.15; March 31, 2006 - C$64.90; December 31, 2005 - C$57.63). 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 each quarter 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, 2007 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, 2007. 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 2007 increased to a record $1,622 million from $1,039 million for the first quarter of 2006, and increased from $1,293 million in the prior quarter. The increase from the first quarter of 2006 was primarily due to the impact of increased crude oil pricing related to a narrower Heavy Differential, increased sales volumes, decreased realized risk management losses, and a slightly weaker Canadian dollar relative to the US dollar. These factors were partially offset by decreased natural gas pricing and increased production expense. The increase from the prior quarter was primarily due to increased crude oil pricing related to a narrower Heavy Differential, increased natural gas pricing, a full quarter of production from the Anadarko Canada Corporation ("ACC") acquisition, decreased realized risk management losses on crude oil, and the impact of a slightly weaker Canadian dollar relative to the US dollar, partially offset by decreased crude oil and NGLs sales volumes.

Total production before royalties increased 9% to average 613,114 boe/d for the first quarter of 2007 from 563,027 boe/d for the first quarter of 2006, and was comparable to 613,764 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 2007**		Dec 31 2006		Sep 30 2006		Jun 30 2006
Revenue, before royalties (1)	**$**	**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

		Mar 31 2006		Dec 31 2005		Sep 30 2005		Jun 30 2005
Revenue, before royalties (1)	$	2,668	$	3,319	$	3,163	$	2,420
Net earnings	$	57	$	1,104	$	151	$	219
Net earnings per common share								
– Basic and diluted	$	0.11	$	2.06	$	0.28	$	0.41

(1) Blending costs that were netted against gross revenues in prior periods have been reclassified to transportation expense to conform to the presentation adopted in the fourth quarter of 2006.

Net earnings over the eight most recently completed quarters generally reflected fluctuations in realized crude oil and natural gas prices, increased sales volumes and the impact of mark-to-market accounting treatment of financial instruments. More specifically, volatility in quarterly net earnings was primarily due to:

- Crude oil pricing. Crude oil prices reflected demand growth, continued geopolitical uncertainties and a narrower Heavy Differential. Hurricane activity in the Gulf of Mexico in the third quarter of 2005 further contributed to increased world benchmark crude oil prices.
- Natural gas pricing. Natural gas prices primarily reflected fluctuations in demand for natural gas and inventory levels as a result of colder temperatures in North America during the first quarter of 2007, milder temperatures experienced during 2006 and hurricane activity in the third quarter of 2005.
- Crude oil and NGLs sales volumes. Crude oil and NGLs sales volumes primarily reflected increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake polymer flood project, additional production volumes from the ACC acquisition completed in the fourth quarter of 2006, development of West and East Espoir, and production from the Baobab Field located offshore Côte d'Ivoire. Production from the Baobab Field commenced in the third quarter of 2005.
- Natural gas sales volumes. Natural gas sales volumes reflected additional natural gas production from the ACC acquisition and internally generated growth. The increase was partially offset by the production decrease due to the Company's strategic reduction in natural gas drilling activity and increased North America crude oil drilling, made in response to low natural gas prices in 2006 and inflationary cost pressures.
- The value of the Canadian dollar relative to the US dollar. A fluctuating Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil sales, as crude oil prices are based on US dollar denominated benchmarks.
- Unrealized gains and losses from the mark-to-market treatment of the Company's commodity price hedges.
- Jurisdictional tax rate changes substantively enacted in a period.
- Unrealized foreign exchange gains and losses due to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt and working capital in North America denominated in US dollars, as well as the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling.

- Unrealized expenses and recoveries due to the mark-to-market treatment of the Company's stock-based compensation liability. The liability reflected a general increase in the Company's share price over the eight most recently completed quarters.
- Increased production expense primarily due to industry-wide inflationary cost pressures.
- Increased depletion, depreciation and amortization expense primarily associated with the ACC acquisition, increased finding and development costs associated with crude oil and natural gas exploration in North America and increased estimated future costs to develop the Company's proved undeveloped reserves.

OPERATING HIGHLIGHTS

	Three Months Ended		
	Mar 31 2007	Dec 31 2006	Mar 31 2006
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 51.71**	$ 47.27	$ 43.79
Royalties	**4.92**	4.10	3.48
Production expense	**13.81**	12.32	11.33
Netback	**$ 32.98**	$ 30.85	$ 28.98
Natural gas ($/mcf) (1)			
Sales price (2)	**$ 7.74**	$ 6.66	$ 8.30
Royalties	**1.48**	1.26	1.70
Production expense	**0.97**	0.86	0.80
Netback	**$ 5.29**	$ 4.54	$ 5.80
Barrels of oil equivalent ($/boe) (1)			
Sales price (2)	**$ 49.32**	$ 43.91	$ 46.30
Royalties	**6.76**	5.62	6.44
Production expense	**10.10**	9.16	8.46
Netback	**$ 32.46**	$ 29.13	$ 31.40

(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 2007	Dec 31 2006	Mar 31 2006
WTI benchmark price (US$/bbl)	**$ 58.23**	$ 60.21	$ 63.53
Dated Brent benchmark price (US$/bbl)	**$ 57.76**	$ 59.68	$ 61.80
Differential to LLB blend (US$/bbl)	**$ 15.80**	$ 21.31	$ 28.70
LLB blend differential from WTI (%)	**27%**	35%	45%
Condensate benchmark price (US$/bbl)	**$ 58.78**	$ 59.59	$ 63.63
NYMEX benchmark price (US$/mmbtu)	**$ 6.96**	$ 6.61	$ 9.10
AECO benchmark price (C$/GJ)	**$ 7.07**	$ 6.03	$ 8.82
US / Canadian dollar average exchange rate (US$)	**$ 0.8535**	$ 0.8781	$ 0.8660

Commodity Prices

WTI averaged US$58.23 per bbl for the first quarter of 2007, a decrease of 8% from US$63.53 per bbl for the first quarter of 2006, and a decrease of 3% from the prior quarter. World benchmark crude oil prices during the first quarter fluctuated due to demand/supply dynamics, timing of US refineries turnarounds and geopolitical uncertainties.

The Company's realized crude oil prices increased from the first quarter of 2006 and the prior quarter primarily as a result of the narrower Heavy Differential and a weaker Canadian dollar relative to the US dollar, partially offset by a decreased WTI price. Heavy Differentials averaged 27% for the first quarter of 2007 compared to 45% for the first quarter of 2006, and 35% for the prior quarter. The narrowing of the Heavy Differentials from the comparable periods in 2006 was primarily due to reduced availability of imported grades from Venezuela and Mexico, reduced Canadian production of heavy crude oil and the removal of logistical constraints in accessing new markets in the US Gulf Coast due to the Pegasus and Spearhead pipelines commencing operations during 2006. The weaker Canadian dollar increased the Canadian dollar sales price the Company received for its crude oil sales, as crude oil prices are based on US dollar denominated benchmarks.

The Company anticipates continued volatility in the crude oil markets given the unpredictable nature of geopolitical events.

Dated Brent ("Brent") averaged US$57.76 per bbl for the first quarter of 2007, a decrease of 7% compared to US$61.80 per bbl for the first quarter of 2006, and a decrease of 3% from US$59.68 per bbl for the prior quarter. Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Brent pricing, which generally continued to benefit from strong European and Asian demand in the first quarter of 2007. Particularly cold winter temperatures in Europe during the first quarter of 2007 increased demand in the European market, further supporting Brent pricing.

NYMEX natural gas prices averaged US$6.96 per mmbtu for the first quarter of 2007, a decrease of 24% from US$9.10 per mmbtu for the first quarter of 2006, and an increase of 5% from US$6.61 per mmbtu for the prior quarter. AECO natural gas prices for the first quarter of 2007 decreased 20% from $8.82 per GJ in the first quarter of 2006 to average $7.07 per GJ, and increased 17% from $6.03 per GJ for the prior quarter. The increase in natural gas prices in the first quarter of 2007 from the prior quarter was primarily due to colder winter temperatures in North America during February and March, which more closely reflected historical averages, and the production volume impact of an overall reduction in natural gas drilling activity in response to industry wide inflationary pressures. Reduced drilling activity and production volumes decreased natural gas inventories closer to historical levels.

Longer-term natural gas prices will continue to be weather dependent.

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 production and capital cost pressures throughout the North America oil and gas industry, particularly related to natural gas drilling activity and oil sands developments. The strong commodity price environment has also impacted costs in international basins. Specifically, the high demand for offshore drilling rigs continues.

The crude oil and natural gas industry is also experiencing cost pressures related to increasingly stringent environmental regulations, both in North America and internationally. In Canada, Federal and Provincial governments are in the process of drafting policy and legislation to control greenhouse gas emissions. As a majority of the Company's operations are in the high cost and highly regulated environment of the Western Canadian Sedimentary Basin, additional cost requirements as a result of greenhouse gas legislation may add to the challenge of executing projects within this basin.

The Alberta provincial government is currently reviewing the oil and gas royalty regime, which may result in changes to the Company's royalty obligations in future years.

The increased cost pressures, the outcome of the royalty review, and the impact of environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects.

PRODUCT PRICES [1]

	Three Months Ended		
	Mar 31 2007	Dec 31 2006	Mar 31 2006
Crude oil and NGLs ($/bbl) [2]			
North America	**$ 46.09**	$ 40.27	$ 34.16
North Sea	**$ 68.83**	$ 67.72	$ 68.05
Offshore West Africa	**$ 58.60**	$ 63.50	$ 65.23
Company average	**$ 51.71**	$ 47.27	$ 43.79
Natural gas ($/mcf) [2]			
North America	**$ 7.79**	$ 6.70	$ 8.39
North Sea	**$ 4.49**	$ 3.48	$ 2.38
Offshore West Africa	**$ 5.97**	$ 5.72	$ 5.59
Company average	**$ 7.74**	$ 6.66	$ 8.30
Company average ($/boe) [2]	**$ 49.32**	$ 43.91	$ 46.30
Percentage of revenue (excluding midstream revenue)			
Crude oil and NGLs	**56%**	60%	53%
Natural gas	**44%**	40%	47%

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

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

The Company's realized crude oil prices increased 18% to average $51.71 per bbl for the first quarter of 2007 from $43.79 per bbl for the first quarter of 2006, and increased 9% from $47.27 per bbl for the prior quarter. The Company's realized crude oil prices increased from the first quarter of 2006 and the prior quarter primarily as a result of a narrower Heavy Differential and a weaker Canadian dollar relative to the US dollar, partially offset by a decreased WTI benchmark price.

The Company's realized natural gas price decreased 7% to average $7.74 per mcf for the first quarter of 2007 from $8.30 per mcf for the first quarter of 2006, and increased 16% from $6.66 per mcf for the prior quarter. The increase in realized natural gas prices from the prior quarter primarily reflected colder winter temperatures during the first quarter of 2007, which more closely reflected historical averages, and the impact of an overall reduction in natural gas drilling activity in response to industry wide inflationary pressures. Reduced drilling activity and production volumes decreased natural gas inventories closer to historical levels.

North America

North America realized crude oil prices increased 35% to average $46.09 per bbl for the first quarter of 2007 from $34.16 per bbl for the first quarter of 2006, and increased 14% from $40.27 per bbl for the prior quarter. The increase from the comparable periods was due to a narrower Heavy Differential and weaker Canadian dollar, partially offset by a decreased WTI price.

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 135,000 bbl/d of heavy crude oil blends to the Western Canadian Select ("WCS") stream. The Company also continues to work with refiners to advance expansion of heavy crude oil conversion capacity, and is working with pipeline companies to develop new capacity to the Canadian West Coast and the US Gulf Coast where crude oil cargos can be sold on a world-wide basis. With a view to expanding markets for its heavy crude oil, the Company has committed to 25,000 bbl/d of capacity on the Pegasus Pipeline, which carries crude oil to the Gulf of Mexico. The Pegasus Pipeline is made up of a series of segments extending near the Gulf Coast**.**

North America realized natural gas prices decreased 7% to average $7.79 per mcf for the first quarter of 2007 from $8.39 per mcf for the first quarter of 2006, and increased 16% from $6.70 per mcf for the prior quarter. The increase in realized natural gas prices from the prior quarter primarily reflected colder winter temperatures and decreased natural gas inventories that were closer to historical levels.

A comparison of the price received for the Company's North America production by product type is as follows:

	Mar 31 2007	Dec 31 2006	Mar 31 2006
Wellhead Price (1) (2)			
Light / medium crude oil and NGLs (C$/bbl)	**$ 59.48**	$ 54.11	$ 58.21
Pelican Lake crude oil (C$/bbl)	**$ 44.44**	$ 37.89	$ 31.60
Primary heavy crude oil (C$/bbl)	**$ 41.83**	$ 36.16	$ 25.91
Thermal heavy crude oil (C$/bbl)	**$ 40.31**	$ 36.06	$ 23.60
Natural gas (C$/mcf)	**$ 7.79**	$ 6.70	$ 8.39

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

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

North Sea

North Sea realized crude oil prices increased marginally to average $68.83 per bbl for the first quarter of 2007 from $68.05 per bbl for the first quarter of 2006, and from $67.72 per bbl for the prior quarter. Realized crude oil prices in the North Sea during the first quarter continued to benefit from the impact of strong European and Asian demand on Brent pricing, a weaker Canadian dollar and the timing of liftings.

Offshore West Africa

Offshore West Africa realized crude oil prices decreased 10% to average $58.60 per bbl for the first quarter of 2007 from $65.23 per bbl for the first quarter of 2006, and decreased 8% from $63.50 per bbl for the prior quarter. Realized crude oil prices Offshore West Africa during the first quarter continued to benefit from the impact of strong European and Asian demand on Brent pricing, a weaker Canadian dollar and the timing of liftings.

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 inventory volumes by segment, which have not been recognized in revenue, were as follows:

(bbl)	**Mar 31 2007**	Dec 31 2006
North America, related to pipeline fill	**1,097,526**	1,097,526
North Sea, related to timing of liftings	**401,296**	910,796
Offshore West Africa, related to timing of liftings	**230,623**	113,774
	1,729,445	2,122,096

In the first quarter of 2007, additional net sales of approximately 395,000 barrels of crude oil produced in the Company's international operations, which were deferred and included in inventory at December 31, 2006, were included in the first quarter results of operations. Notwithstanding these additional sales volumes, cash flow from operations decreased by approximately $2 million in the first quarter of 2007 as increased cash flow derived from additional sales volumes in the North Sea was more than offset by decreases in cash flows due to lower sales volumes in Offshore West Africa.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2007	Dec 31 2006	Mar 31 2006
Crude oil and NGLs (bbl/d)			
North America	**237,489**	249,565	222,955
North Sea	**61,869**	61,786	60,802
Offshore West Africa	**27,643**	32,354	39,905
	327,001	343,705	323,662
Natural gas (mmcf/d)			
North America	**1,694**	1,594	1,411
North Sea	**15**	16	17
Offshore West Africa	**8**	10	8
	1,717	1,620	1,436
Total barrel of oil equivalent (boe/d)	**613,114**	613,764	563,027
Product mix			
Light/medium crude oil and NGLs	**24%**	24%	27%
Pelican Lake crude oil	**5%**	5%	5%
Primary heavy crude oil	**15%**	15%	17%
Thermal heavy crude oil	**9%**	12%	8%
Natural gas	**47%**	44%	43%

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2007	Dec 31 2006	Mar 31 2006
Crude oil and NGLs (bbl/d)			
North America	**204,401**	217,751	192,747
North Sea	**61,754**	61,658	60,694
Offshore West Africa	**25,897**	30,817	38,958
	292,052	310,226	292,399
Natural gas (mmcf/d)			
North America	**1,367**	1,291	1,120
North Sea	**15**	16	17
Offshore West Africa	**8**	9	8
	1,390	1,316	1,145
Total barrel of oil equivalent (boe/d)	**523,730**	529,515	483,143

Daily production and per barrel statistics are presented throughout the 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 613,114 boe/d for the first quarter of 2007, a 9% increase from 563,027 boe/d for the first quarter of 2006, and was comparable to 613,764 boe/d for the prior quarter.

Total crude oil and NGLs production for the first quarter of 2007 of 327,001 bbl/d was comparable to 323,662 bbl/d for the first quarter of 2006, and decreased 5% from 343,705 bbl/d for the prior quarter. The decrease from the prior quarter was primarily due to the timing of steaming cycles related to the Company's thermal crude oil projects in North America and planned maintenance activities at the Espoir Field. Notwithstanding these factors, crude oil and NGLs production in the first quarter of 2007 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 47% of the Company's total production. Natural gas production for the first quarter of 2007 averaged a record 1,717 mmcf/d compared to 1,436 mmcf/d for the first quarter of 2006 and 1,620 mmcf/d for the prior quarter. The increase in natural gas production from the comparable periods primarily reflected a full quarter impact of the ACC acquisition completed in the fourth quarter of 2006 and the completion of scheduled natural gas drilling activity in advance of spring break up. The increase from the first quarter of 2006 was partially offset by the production decrease due to the Company's strategic reduction in natural gas drilling activity and increased North America crude oil drilling, made in response to sustained low natural gas prices and inflationary cost pressures. First quarter natural gas production was at the high end of the Company's previously issued guidance of 1,696 to 1,717 mmcf/d.

Annual production guidance for 2007 is forecasted to average between 315,000 and 360,000 bbl/d of crude oil and NGLs and between 1,594 and 1,664 mmcf/d of natural gas. Second quarter 2007 production guidance is forecasted to average between 313,000 and 329,000 bbl/d of crude oil and NGLs and between 1,677 and 1,698 mmcf/d of natural gas.

North America

North America crude oil and NGLs production for the first quarter of 2007 increased 7% to average 237,489 bbl/d from 222,955 bbl/d for the first quarter of 2006, and decreased 5% from 249,565 bbl/d for the prior quarter. The increase in crude oil and NGLs production from the first quarter of 2006 was primarily due to increased production from the Company's Primrose thermal projects, the positive results from the Pelican Lake waterflood project and the ACC acquisition. The decrease from the prior quarter was primarily due to the timing of steaming cycles related to the Company's thermal crude oil projects.

North America natural gas production increased 20% to average a record 1,694 mmcf/d for the first quarter of 2007 from 1,411 mmcf/d for the first quarter of 2006, and increased 6% from 1,594 mmcf/d for the prior quarter. The increase in natural gas production from the comparable periods reflected a full quarter impact of the ACC acquisition and the completion of scheduled natural gas drilling activity in advance of spring break up. The increase from the first quarter of 2006 was partially offset by production declines due to the Company's decision to reduce natural gas drilling activity. The ACC acquisition was completed in the fourth quarter of 2006 and to date, the properties are performing better than expected.

North Sea

North Sea crude oil production of 61,869 bbl/d for the first quarter of 2007 was comparable to 60,802 bbl/d for the first quarter of 2006 and 61,786 bbl/d for the prior quarter. Production levels for the first quarter of 2007 were in line with expectations.

Crude oil production volumes are anticipated to decrease in the second and third quarters of 2007 due to planned maintenance shutdowns.

Offshore West Africa

Offshore West Africa crude oil production decreased 31% to average 27,643 bbl/d for the first quarter of 2007 from 39,905 bbl/d for the first quarter of 2006, and decreased 15% from 32,354 bbl/d for the prior quarter. First quarter production reflected a decrease due to planned maintenance activities at the Espoir Field and continued challenges with sand and solids production at the Baobab Field where 5 production wells have been shut in. The Company has secured a deepwater rig for mobilization expected in late 2007 that should enable the Company to recomplete these wells in 2008.

ROYALTIES

	Three Months Ended		
	Mar 31 2007	Dec 31 2006	Mar 31 2006
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 6.42**	$ 5.13	$ 4.63
North Sea	**$ 0.13**	$ 0.14	$ 0.12
Offshore West Africa	**$ 3.70**	$ 3.02	$ 1.55
Company average	**$ 4.92**	$ 4.10	$ 3.48
Natural gas ($/mcf) [1]			
North America	**$ 1.50**	$ 1.29	$ 1.73
North Sea	**$ -**	$ -	$ -
Offshore West Africa	**$ 0.38**	$ 0.27	$ 0.13
Company average	**$ 1.48**	$ 1.26	$ 1.70
Company average ($/boe) [1]	**$ 6.76**	$ 5.62	$ 6.44
Percentage of revenue [2]			
Crude oil and NGLs	**10%**	9%	8%
Natural gas	**19%**	19%	21%
Company average boe	**14%**	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 NGL royalties per bbl for the first quarter of 2007 were primarily a reflection of increased realized crude oil prices and the full recovery of the Company's capital investments in the Primrose North and South Fields in the third quarter of 2006. Upon full recovery, Crown royalty rates on the Primrose North and South Fields increased from 1% of gross revenue to 25% of gross revenue less operating, capital and abandonment costs. Crude oil and NGL royalties averaged approximately 14% of gross revenues in the first quarter of 2007 and 2006 and 13% for the prior quarter. Crude oil and NGLs royalties per bbl are anticipated to be 14% to 16% of gross revenues for the year.

Natural gas royalties per mcf fluctuate in correlation with natural gas prices. Natural gas royalties averaged approximately 19% of gross revenues in the first quarter of 2007 compared to 21% for the first quarter of 2006 and 19% for the prior quarter. Natural gas royalties are anticipated to be 21% to 23% of gross revenues for the year.

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. These combined revenues are reported as sales revenue. 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 to 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 PSCs. The Company's capital investment in the Baobab Field is not expected to be fully recovered until approximately 2012 due to the ongoing production curtailments resulting from limitations to sand screen effectiveness.

Royalty rates as a percentage of gross revenue averaged approximately 6% for the first quarter of 2007 compared to 2% for first quarter of 2006 and 5% for the prior quarter. The increase in royalty rates from the comparable periods was due to the Company's full recovery of its capital investment in the Espoir Field in the first quarter and the resulting increase in profit oil on which the Government's entitlement is based. Offshore West Africa royalty rates are anticipated to be 13% to 15% of gross revenues for the year.

PRODUCTION EXPENSE

	Three Months Ended		
	Mar 31 2007	Dec 31 2006	Mar 31 2006
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 13.00**	$ 12.13	$ 10.91
North Sea	**$ 18.57**	$ 14.76	$ 16.85
Offshore West Africa	**$ 8.93**	$ 10.05	$ 6.08
Company average	**$ 13.81**	$ 12.32	$ 11.33
Natural gas ($/mcf) (1)			
North America	**$ 0.95**	$ 0.84	$ 0.79
North Sea	**$ 2.58**	$ 1.54	$ 1.26
Offshore West Africa	**$ 1.48**	$ 2.01	$ 1.00
Company average	**$ 0.97**	$ 0.86	$ 0.80
Company average ($/boe) (1)	**$ 10.10**	$ 9.16	$ 8.46

(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 2007 increased to $13.00 per bbl from $10.91 per bbl for the first quarter of 2006 and increased from $12.13 per bbl for the prior quarter. First quarter production expense primarily reflected continued inflated industry-wide service costs, the timing of steaming cycles related to the Company’s thermal crude oil projects, and increased operating costs related to additional injection wells as part of the Company’s commercial polymer flood project.

North America natural gas production expense per mcf for the first quarter of 2007 increased over the comparable periods primarily due to increased seasonal costs related to winter access areas and continued industry-wide cost pressures.

Should commodity prices remain relatively stable, production expense per boe is anticipated to level out in 2007 as a result of lower industry activity.

North Sea

North Sea crude oil production expense varied on a per barrel basis from the comparable periods due to varying sales volumes on a relatively fixed cost base and the timing of liftings from various fields. Crude oil production expense is anticipated to increase on a per barrel basis during the second and third quarters of 2007 due to planned maintenance shutdowns.

Offshore West Africa

Offshore West Africa crude oil production expense on a per barrel basis varied from the comparable periods primarily due to continuing operating challenges with sand and solids resulting in decreased production volumes at Baobab, on a relatively fixed operating cost base and the timing of repair and maintenance work.

MIDSTREAM

($ millions)	Three Months Ended **Mar 31 2007**	Dec 31 2006	Mar 31 2006
Revenue	**$ 19**	$ 18	$ 18
Production expense	**6**	6	5
Midstream cash flow	**13**	12	13
Depreciation	**2**	2	2
Segment earnings before taxes	**$ 11**	$ 10	$ 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 2007**	Dec 31 2006	Mar 31 2006
Expense ($ millions)	**$ 707**	$ 722	$ 519
$/boe [2]	**$ 12.73**	$ 12.80	$ 10.56

(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 2007 increased in total and on a boe basis from the first quarter of 2006 and was comparable to the prior quarter. The increase from the first quarter of 2006 was primarily as a result of increased production combined with overall increases in finding and development costs associated with crude oil and natural gas exploration in North America, a higher depletion base due to the ACC acquisition, and increased estimated future costs to develop the Company's proved undeveloped reserves.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended		
	Mar 31 2007	Dec 31 2006	Mar 31 2006
Expense ($ millions)	**$ 18**	$ 18	$ 17
$/boe (1)	**$ 0.32**	$ 0.32	$ 0.34

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

Asset retirement obligation accretion expense is the increase in the carrying amount of the asset retirement obligation due to the passage of time. Accretion expense for the first quarter of 2007 was consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended		
	Mar 31 2007	Dec 31 2006	Mar 31 2006
Net expense ($ millions)	**$ 60**	$ 57	$ 42
$/boe (1)	**$ 1.08**	$ 1.01	$ 0.85

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

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

STOCK-BASED COMPENSATION EXPENSE

	Three Months Ended		
($ millions)	**Mar 31 2007**	Dec 31 2006	Mar 31 2006
Stock-based compensation expense	**$ 25**	$ 176	$ 132

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.

The Company recorded a $25 million ($17 million after-tax) stock-based compensation expense for the first quarter of 2007 in connection with the 3% increase in the Company's share price (Company's share price as at: March 31, 2007 – C$63.75; December 31, 2006 - C$62.15; March 31, 2006 - C$64.90; December 31, 2005 - C$57.63). 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, 2007, the Company capitalized $9 million in stock-based compensation on the Horizon Project (December 31, 2006 - $41 million; March 31, 2006 - $30 million). 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, 2007. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the three months ended March 31, 2007, the Company paid $136 million for stock options surrendered for cash settlement (December 31, 2006 - $48 million; March 31, 2006 - $123 million).

INTEREST EXPENSE

	Three Months Ended		
($ millions)	**Mar 31 2007**	Dec 31 2006	Mar 31 2006
Interest expense, gross	**$ 154**	$ 128	$ 58
Less: capitalized interest, Horizon Project	**71**	66	33
Interest expense, net	**$ 83**	$ 62	$ 25
$/boe (1)	**$ 1.49**	$ 1.08	$ 0.51
Average effective interest rate	**5.4%**	5.6%	5.7%

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

Gross interest expense increased from the comparable periods substantially due to increased debt levels associated with the ACC acquisition and the financing of Horizon Project capital expenditures. The increase from the comparable periods also reflected the impact of the slightly weaker Canadian dollar relative to the US dollar that increased interest expense on the Company's US dollar denominated debt securities.

The Company's average effective interest rate is anticipated to increase, reflecting the impact of higher cost US dollar debt securities issued in March 2007.

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.

As disclosed in note 2 to the Company's unaudited interim consolidated financial statements as at March 31, 2007, commencing January 1, 2007, the Company adopted new accounting standards issued by the Canadian Institute of Chartered Accountants relating to the accounting for and disclosure of financial instruments and comprehensive income.

Adoption of these standards required the Company to record all of its derivative financial instruments on the balance sheet at estimated fair value as at January 1, 2007, including those designated as hedges. Designated hedges, other than cross currency interest rate swaps, were previously not recognized on the balance sheet but were disclosed in the notes to the financial statements. The adjustment to recognize the designated hedges on the balance sheet was recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

With the exception of the foreign currency translation adjustment, these standards were adopted prospectively; accordingly, comparative amounts for prior periods have not been restated. The reclassification of the foreign currency translation adjustment to other comprehensive income was applied retroactively with prior period restatement.

The effects of adopting these standards on the opening balance sheet were as follows:

($ millions)	Jan 1, 2007
Increased current portion of other long-term assets (1)	$ 193
Decreased other long-term assets (2)	$ (16)
Decreased long-term debt (3)	$ (72)
Increased retained earnings (4)	$ 10
Increased foreign currency translation adjustment (5)	$ 13
Increased accumulated other comprehensive income (6)	$ 146
Decreased current portion of future income tax asset (7)	$ (62)
Increased future income tax liability (7)	$ 18

(1) Relates to the recognition of the current portion of the fair value of derivative financial instruments designated as cash flow hedges.

(2) Relates to the recognition of the long-term portion of the fair value of derivative financial instruments designated as cash flow and fair value hedges, as well as the reclassification of transaction costs and original issue discounts from deferred charges to long-term debt.

(3) Relates to the fair value impact of derivative financial instruments designated as fair value hedges, as well as the reclassification of transaction costs and original issue discounts.

(4) Relates to the impact on adoption of the measurement of ineffectiveness on derivative financial instruments designated as cash flow hedges.

(5) Relates to the retroactive restatement of foreign currency translation adjustment to accumulated other comprehensive income.

(6) Relates to the recognition of accumulated other comprehensive income arising from the measurement of effectiveness on derivative financial instruments designated as cash flow hedges.

(7) Relates to the future income tax impacts of the above noted adjustments.

Effective January 1, 2007, the Company's accounting policies for financial instruments and comprehensive income are as follows:

All derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these 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 Company formally documents all derivative financial instruments designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in consolidated net earnings in the same period or periods in which the crude oil or natural gas is sold. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in consolidated net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in consolidated net earnings.

The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in consolidated net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in consolidated net earnings.

Cross currency swap contracts are periodically used 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. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges are included in foreign exchange in consolidated net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in consolidated net earnings.

Gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income on the consolidated balance sheets and amortized into consolidated net earnings in the period in which the underlying hedged item is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in consolidated net earnings. Gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability and original issue discounts on long-term debt have been included in the carrying value of the financial asset or liability and are amortized to consolidated net earnings over the life of the financial instrument using the effective interest method.

RISK MANAGEMENT

($ millions)	Three Months Ended **Mar 31 2007**	Dec 31 2006	Mar 31 2006
Realized (gain) loss			
Crude oil and NGLs financial instruments	**$ (5)**	$ 223	$ 332
Natural gas financial instruments	**(83)**	(97)	56
	$ (88)	$ 126	$ 388
Unrealized loss (gain)			
Crude oil and NGLs financial instruments	**$ 330**	$ (239)	$ 114
Natural gas financial instruments	**206**	8	(104)
Interest rate swaps [1]	**-**	-	(2)
	$ 536	$ (231)	$ 8
Total	**$ 448**	$ (105)	$ 396

(1) Certain prior period amounts have been reclassified with respect to cross currency swaps.

The net realized (gains) losses from crude oil and NGLs and natural gas financial instruments (increased) decreased the Company's average realized prices as follows:

	Three Months Ended **Mar 31 2007**	Dec 31 2006	Mar 31 2006
Crude oil and NGLs ($/bbl) [1]	**$ (0.17)**	$ 7.09	$ 12.04
Natural gas ($/mcf) [1]	**$ (0.54)**	$ (0.65)	$ 0.43

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

As disclosed in note 2 to the Company's unaudited interim consolidated financial statements as at March 31, 2007, commencing January 1, 2007, the Company now records all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. As at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million.

As effective as the Company's hedges are against reference commodity prices, a substantial portion of the derivative financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The change in the fair value of the 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, 2007. Due to changes in the crude oil and natural gas forward pricing, and the reversal of prior year unrealized gains, the Company recorded a net unrealized loss of $536 million ($362 million after-tax) on its commodity risk management activities for the three months ended March 31, 2007 (December 31, 2006 - unrealized gain of $231 million, $158 million after-tax; March 31, 2006 - unrealized loss of $8 million, $5 million after-tax).

Details related to outstanding derivative financial instruments at March 31, 2007 are disclosed in note 10 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

($ millions)	Three Months Ended **Mar 31 2007**	Dec 31 2006	Mar 31 2006
Realized foreign exchange loss (gain)	**$ 5**	$ (20)	$ (5)
Unrealized foreign exchange (gain) loss (1)	**(32)**	161	10
	$ (27)	$ 141	$ 5

(1) Amounts are reported net of the hedging effect of cross currency interest rate 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 are subject to fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar on North Sea operations. 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 realized foreign exchange loss for the three months ended March 31, 2007 was primarily the result of foreign exchange rate fluctuations on working capital items denominated in US dollars or UK pounds sterling. The unrealized foreign exchange gain for the three months ended March 31, 2007 was primarily related to the first quarter strengthening of the Canadian dollar in relation to the US dollar with respect to the US dollar debt, and working capital in North America denominated in US dollars. The Canadian dollar ended the first quarter at US$0.8674 compared to US$0.8581 at December 31, 2006 (March 31, 2006 - US$0.8568).

During the first quarter of 2007, the Company de-designated the portion of the US dollar denominated debt previously hedged against its net investment in US dollar based self-sustaining foreign operations. Accordingly, all foreign exchange (gains) losses arising each period on U.S. dollar denominated long-term debt are now recognized in the consolidated statement of earnings.

TAXES

($ millions, except income tax rates)	Three Months Ended Mar 31 2007	Dec 31 2006	Mar 31 2006
Taxes other than income tax			
Current	**$ 66**	$ 44	$ 35
Deferred	**(3)**	(3)	26
	$ 63	$ 41	$ 61
Current income tax			
North America	**$ 25**	$ 51	$ 18
North Sea	**35**	30	1
Offshore West Africa	**10**	14	13
	$ 70	$ 95	$ 32
Future income tax expense	**$ 100**	$ 135	$ 268
Effective income tax rate	**38.7%**	42.3%	83.9% (1)

(1) Includes the effect of a charge of $110 million related to the increased supplementary charge on oil and gas profits in the UK North Sea, substantively enacted in the first quarter of 2006.

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 and amount of capital expenditures incurred in Canada in any particular year.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Mar 31 2007	Dec 31 2006	Mar 31 2006
Expenditures on property, plant and equipment			
Net property acquisitions	**$ 46**	$ 4,720	$ 12
Land acquisition and retention	**29**	28	99
Seismic evaluations	**50**	17	52
Well drilling, completion and equipping	**714**	462	936
Pipeline and production facilities	**334**	311	500
Total net reserve replacement expenditures	**1,173**	5,538	1,599
Horizon Project:			
Phase 1 construction costs	**674**	745	616
Phases 2 and 3 costs	**44**	54	1
Capitalized interest, stock-based compensation and other	**91**	134	69
Total Horizon Project	**809**	933	686
Midstream	**2**	1	3
Abandonments [2]	**20**	19	15
Head office	**5**	6	6
Total net capital expenditures	**$ 2,009**	$ 6,497	$ 2,309
By segment			
North America	**$ 998**	$ 5,296	$ 1,404
North Sea	**138**	211	138
Offshore West Africa	**36**	30	50
Other	**1**	1	7
Horizon Project	**809**	933	686
Midstream	**2**	1	3
Abandonments [2]	**20**	19	15
Head office	**5**	6	6
Total	**$ 2,009**	$ 6,497	$ 2,309

(1) Net capital expenditures do not include non-cash property, plant and equipment additions or disposals.

(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 in the first quarter of 2007 were $2,009 million compared to $2,309 million in the first quarter of 2006 and $6,497 million in the prior quarter. First quarter 2007 capital expenditures reflected the continued progress on the Company's larger, future growth projects, most notably the Horizon Project, as well as overall industry-wide inflationary pressures. The decrease in capital expenditures from the prior quarter primarily related to the $4,641 million acquisition of ACC (including working capital and other adjustments) in the fourth quarter of 2006.

In the first quarter of 2007, the Company drilled a total of 688 net wells consisting of 201 natural gas wells, 193 crude oil wells, 234 stratigraphic test and service wells and 60 wells that were dry. The Company achieved an overall success rate of 87% for the first quarter of 2007, excluding stratigraphic test and service wells, compared to 90% for the first quarter of 2006 and 89% for the prior quarter**.**

North America

North America, including the Horizon Project, accounted for approximately 91% of the total capital expenditures for the first quarter of 2007 compared to approximately 92% for the first quarter of 2006 and 96% for the prior quarter.

During the first quarter of 2007, the Company targeted 245 net natural gas wells, including 49 wells in Northeast British Columbia, 92 wells in the Northern Plains region, 78 wells in Northwest Alberta, and 26 wells in the Southern Plains region. The Company also targeted 207 net crude oil wells during the quarter. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 144 heavy crude oil wells, 36 Pelican Lake crude oil wells, 9 thermal crude oil wells and 5 light crude oil wells were drilled. Another 13 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, the Company continues to access its large crude oil drilling inventory to maximize value in both the short and long term. To optimize netbacks in the short term, the Company focused on drilling crude oil wells in the first quarter of 2007 and, accordingly, natural gas drilling activities were reduced to manage overall capital spending. Deferred natural gas wells locations have been retained in the Company's prospect inventory, and will be drilled as natural gas commodity prices improve. Drilling on ACC acquired lands was optimized as part of the overall capital program.

In November of 2005, the Company announced a phased expansion of its In-Situ Oil Sands Assets. As part of the development, the Company is continuing to develop its Primrose thermal projects. During the first quarter of 2007, the Company drilled 128 stratigraphic test wells and observation wells, 2 water source wells and 9 thermal oil wells. Overall Primrose thermal production for the first quarter of 2007 increased to approximately 58,000 bbl/d from approximately 47,000 bbl/d for the first quarter of 2006.

The Primrose East Expansion, a new facility located 15 kilometres from the existing Primrose South steam plant and 25 kilometres from the Wolf Lake central processing facility, is anticipated to add approximately 40,000 bbl/d. The Primrose East Expansion received Board of Directors' sanction in 2006 and regulatory approval in the first quarter of 2007. Drilling and construction are currently underway, and production is expected to commence in 2009.

The next phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 kilometres north of the existing Primrose facilities. The Kirby project is anticipated to add approximately 30,000 bbl/d of production growth. The Company is targeting to file its formal regulatory application documents for this project in the latter half of 2007, with first steaming anticipated to begin in 2011.

Development of new acreage and secondary recovery conversion projects at Pelican Lake continued as expected throughout the first quarter of 2007. Drilling consisted of 36 horizontal wells, with plans to drill 96 additional horizontal wells for the remainder of 2007. The response from the polymer flood pilot continues to be positive. Based on the results of the pilot, the Company commenced the installation of 2 additional polymer skids in the first quarter as part of the commercial polymer flood project. Pelican Lake production averaged approximately 32,000 bbl/d for the first quarter of 2007 compared to 29,000 bbl/d for the first quarter of 2006.

Originally announced in the fall of 2005, the scoping study for the Canadian Natural Upgrader, outside of the Horizon Project, continued into the first quarter of 2007. The terms of reference for this study involved the evaluation of product alternatives, location, technology, gasification and integration with existing assets using the same disciplined approach utilized in the Horizon Project. The next steps in this process would include a Design Basis Memorandum ("DBM") and Engineering Design Specification ("EDS"), which would be required to be completed prior to construction and sanctioning of the project by the Board of Directors.

Based upon the results of the scoping study, which identified growing concerns relating to increased environmental costs for upgraders located in Canada, inflationary capital cost pressures and narrowing heavy oil differentials in North America, the Company has, at this point in time, deferred the DBM and EDS pending clarification on the cost of future environmental legislation and a more stable cost environment.

In the second quarter of 2007, the Company's overall drilling activity in North America is expected to be comprised of 13 natural gas wells and 86 crude oil wells excluding stratigraphic and service wells.

Horizon Project

The Horizon Project continued on schedule and on budget with construction 66% complete at the end of the first quarter. The project status as at March 31, 2007 was as follows:

- Detailed engineering 96% completed;
- Procurement 91% completed with over $5.3 billion in purchase orders and contracts awarded;
- Mine overburden removal approximately 46% completed;
- 2006/2007 drilling program completed;
- Moved crushing plant assemblies for Ore Preparation plant from pre-assemble area to permanent foundations;
- Commenced module setting in Hydrotreater Area;
- Primary Separation Cell ready for hydrotesting;
- High pressure natural gas piping ready for commissioning;
- Completed module fabrication and installation for coker and diluent recovery unit;
- Completed erection of cooling tower; and
- Finished installation of the last remaining 35kV substation.

Major activities for the second quarter of 2007 will include:

- Complete installation of coker and diluent recovery unit process structures;
- Complete Primary Upgrading interconnecting welding on piperacks;
- Energize main electrical substations R1/R2;
- Mechanically complete cooling tower piping;
- 42" water pipeline to be complete and tested; and
- Water pumphouses mechanically complete.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to March 31, 2007 was approximately $4.7 billion. Final construction costs for Phase 1 are expected to exceed the approved budget by 5% to 12% primarily due to inflationary cost pressures.

North Sea

In the first quarter of 2007, 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 2.8 net wells drilling at the end of the quarter.

The development of the Lyell Field progressed during the first quarter. Tranche 1 of the Lyell Field development comprises 2 production wells scheduled for completion in 2007, and 2 production wells and 2 well workovers scheduled for completion in 2008. Full capacity production from the Lyell Field has been deferred to 2008 to optimize capital spending in the North Sea.

During the first quarter, construction of the Columba E Raw Water Injection project continued. Commissioning is scheduled for the second quarter of 2007 when two water injection wells are due to be completed, with production anticipated to reach full capacity in 2008.

Offshore West Africa

During the first quarter of 2007, 1.2 net wells were drilled with 0.6 net wells drilling at the end of the quarter.

First crude oil from West Espoir commenced in 2006 from 3 production wells and 2 injector wells. An additional production well was added during the first quarter of 2007. West Espoir development drilling is expected to continue until 2008 with producers and injectors being brought on-line as they are completed.

The Company purchased a 90% interest in the Olowi PSC offshore Gabon in 2005, and received Government approval and Board sanction for development in 2006. Development plans include a floating production, storage and offtake vessel (“FPSO”), handling production from 4 shallow-water producing platforms. During 2006, the Company signed a lease agreement for a FPSO with a primary term of ten years, commencing 2008. During the first quarter of 2007, the Company awarded additional contracts for the construction of the wellhead towers and secured a drilling rig. Drilling is scheduled to commence mid-2008 with first crude oil anticipated for later in the year. Olowi production is expected to plateau at approximately 20,000 bbl/d.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Mar 31 2007**	Dec 31 2006	Mar 31 2006
Working capital deficit [1]	**$ 1,104**	$ 832	$ 2,065
Long-term debt [2]	**$ 11,307**	$ 11,043	$ 4,342
Shareholders' equity			
Share capital	**$ 2,635**	$ 2,562	$ 2,500
Retained earnings	**8,374**	8,141	5,821
Accumulated other comprehensive loss	**(45)**	(13)	(11)
Total	**$ 10,964**	$ 10,690	$ 8,310
Debt to book capitalization [2] [3]	**50.8%**	50.8%	34.3%
Debt to market capitalization [2]	**24.8%**	24.8%	11.1%
After tax return on average common shareholders' equity [4]	**27.5%**	26.9%	20.3%
After tax return on average capital employed [2] [5]	**16.5%**	17.2%	14.2%

(1) Calculated as current assets less current liabilities.

(2) Long-term debt at March 31, 2007 is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs. Amounts for periods prior to January 1, 2007 were not adjusted for these items.

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

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

(5) Calculated as net earnings plus after-tax interest expense for the twelve month trailing period; as a percentage of average capital employed for the period. Average capital employed is the average shareholders' equity and current and long-term debt for the period.

The Company's capital resources at March 31, 2007 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, 2006 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 five- and ten-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, Baa2 with a stable outlook by Moody's Investor Services, Inc. and BBB with a stable outlook by Standard and Poors Corporation.

At March 31, 2007, the Company had undrawn bank lines of credit of $1,647 million. Details related to the Company's long-term debt at March 31, 2007 are disclosed in note 4 to the Company's unaudited interim consolidated financial statements.

At March 31, 2007, the Company's working capital deficit was $1,104 million and included the current portion of the stock-based compensation liability of $419 million and the current portion of the net mark-to-market liability for risk management derivative financial instruments of $374 million. The settlement of the stock-based compensation liability is dependant 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, 2007.

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. Existing proved development projects, which have largely been funded prior to March 31, 2007, such as Baobab, Primrose and Espoir, and the acquisition of ACC, are anticipated to provide identified growth in production volumes in 2007 through 2009, and generate incremental free cash flows during this period.

Primarily due to the additional debt issued to complete the ACC acquisition in the fourth quarter of 2006, long-term debt increased to $11,307 million at March 31, 2007, resulting in a debt to book capitalization level of 50.8% (December 31, 2006 – 50.8%; March 31, 2006 – 34.3%). While this ratio is above 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 2008. While the Company believes that its balance sheet has the strength and flexibility to accommodate the ACC acquisition and complete Phase 1 of the Horizon Project, to ensure balance sheet strength going forward, the Company has hedged a significant portion of its natural gas and crude oil production for 2007 and 2008 at prices that protect investment returns. In the future, the Company may also consider the divestiture of 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 expenditure program throughout the Horizon Project construction period. This program 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 crude oil put options is in addition to the above parameters. In accordance with the policy, approximately 60% of expected crude oil volumes and approximately 70% of expected natural gas volumes are hedged for the remainder of 2007. In addition, 77,000 bbl/d of crude oil volumes are protected by put options for the remainder of 2007 at a strike price of US$60.00 per barrel.

In addition, the Company has hedged 200,000 bbl/d of crude oil volumes for the year 2008. Of the 200,000 bbl/d, 150,000 bbl/d are hedged by price collars with a US$60.00 floor and 50,000 bbl/d are hedged by put options with a US$55.00 strike price. Subsequent to March 31, 2007, the Company entered into an additional 50,000 bbl/d of price collars with a US$60.00 floor for the first quarter of 2008. In addition, 900,000 GJ/d of natural gas volumes are hedged by price collars for the first quarter of 2008; 400,000 GJ/d with a $7.00 floor and 500,000 GJ/d with a $7.50 floor.

The Company has also reduced its 2007 conventional crude oil and natural gas capital budget by $900 million compared to 2006 capital spending, while maintaining the capital expenditures to complete Phase 1 of the Horizon Project.

Long-term debt

As at March 31, 2007, the Company had in place unsecured bank credit facilities of $6,309 million, comprised of:

- a $100 million demand credit facility;
- a $500 million demand credit facility;
- a 3-year non-revolving syndicated credit facility of $2,350 million;
- a 5-year revolving syndicated credit facility of $1,825 million;
- a 5-year revolving syndicated credit facility of $1,500 million; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities mature June 2011. Both 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 conjunction with the closing of the acquisition of ACC in November 2006, the Company executed a $3,850 million, three-year non-revolving syndicated credit facility maturing in October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million.

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $345 million, including $300 million related to the Horizon Project, were outstanding at March 31, 2007.

Medium-term notes

During the first quarter of 2007, $125 million of 7.40% unsecured debentures due March 1, 2007 were repaid.

The Company has $1,600 million remaining on its $2,000 million shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

US dollar debt securities

In March 2007, the Company issued US$2,200 million of unsecured notes under the US shelf prospectus, comprised of US$1,100 million of unsecured notes maturing May 2017 and US$1,100 million of unsecured notes maturing March 2038, bearing interest at 5.70% and 6.25%, respectively. Concurrently, the Company entered into cross currency interest rate swaps to fix the Canadian dollar interest and principal repayment amounts on US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million. The Company also entered into a cross currency interest rate swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million. 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$100 million remaining on its outstanding US$3,000 million shelf prospectus that allows for the issue of US dollar debt securities in the United States until July 2007. If issued, these securities will bear interest as determined at the date of issuance.

During the first quarter of 2007, the Company de-designated the portion of the US dollar denominated debt previously hedged against its net investment in US dollar based self-sustaining foreign operations. Accordingly, all foreign exchange (gains) losses arising each period on U.S. dollar denominated long-term debt are now recognized in the consolidated statement of earnings.

Share capital

As at March 31, 2007, there were 539,181,000 common shares outstanding and 30,087,000 stock options outstanding. As at April 30, 2007, the Company had 539,263,000 common shares outstanding and 29,078,000 stock options outstanding.

In January 2007, the Company renewed its Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period beginning January 24, 2007 and ending January 23, 2008, up to 26,941,730 common shares or 5% of the outstanding common shares of the Company then outstanding on the date of the announcement. As at April 30, 2007, the Company had not purchased any shares during 2007 under the Normal Course Issuer Bid.

In March 2007, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.34 per common share for 2007. The increase represents a 13% increase from the prior year, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. This is the seventh consecutive year in which the Company has paid dividends and the sixth 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 office space and offshore FPSOs and drilling rigs, and firm commitments for gathering, processing and transmission services, as well as expenditures relating to asset retirement obligations. As at March 31, 2007, 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, 2007:

($ millions)	Remaining 2007	2008	2009	2010	2011	Thereafter
Product transportation and pipeline (1)	$ 172	$ 198	$ 135	$ 123	$ 95	$ 1,043
Offshore equipment operating lease (2)	$ 79	$ 53	$ 52	$ 52	$ 50	$ 132
Offshore drilling (3)	$ 48	$ 83	$ 12	$ 12	$ 7	$ -
Asset retirement obligations (4)	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4,491
Long-term debt (5)	$ 36	$ 45	$ 2,380	$ -	$ 461	$ 6,219
Office lease	$ 24	$ 34	$ 34	$ 36	$ 23	$ -
Electricity and other	$ 40	$ 11	$ 18	$ 18	$ 1	$ -

(1) The Company entered into a 25-year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, annual toll payments before operating costs will be approximately $35 million.

(2) 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. The new FPSO lease agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments throughout 2007 to a maximum of US$395 million.

(3) Subsequent to March 31, 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 to commence in the fourth quarter of 2007, subject to rig availability, with minimum payments estimated to be US$160 million, before joint venture recoveries.

(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 2007 – 2011 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 do not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $2,263 million of revolving bank credit facilities due to the extendable nature of the facilities.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to March 31, 2007 was approximately $4.7 billion. Final construction costs for Phase 1 are expected to exceed the approved budget by 5% to 12% primarily due to inflationary cost pressures.

Legal proceedings

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Company believes that any liabilities that might arise pertaining to 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, 2006.

For the impact of new accounting standards related to financial instruments and comprehensive income, please refer to Risk Management Activities on page 30 of this MD&A and note 2 of the unaudited interim consolidated financial statements as at March 31, 2007.

SENSITIVITY ANALYSIS [1]

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 2007, 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; all other variables are 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 [2]								
Excluding financial derivatives	$	106	$	0.20	$	75	$	0.14
Including financial derivatives	$	3-106	$	0.01-0.20	$	2-75	$	0.00-0.14
Natural gas – AECO C$0.10/mcf [2]								
Excluding financial derivatives	$	28	$	0.05	$	15	$	0.03
Including financial derivatives	$	27-31	$	0.05-0.06	$	18-21	$	0.03-0.04
Volume changes								
Crude oil – 10,000 bbl/d	$	102	$	0.19	$	48	$	0.09
Natural gas – 10 mmcf/d	$	19	$	0.04	$	8	$	0.02
Foreign currency rate change								
$0.01 change in C$ in relation to US$ [2]								
Excluding financial derivatives	$	94-96	$	0.17-0.18	$	24	$	0.04
Interest rate change - 1%	$	37	$	0.07	$	37	$	0.07

(1) The sensitivities are calculated based on 2007 first quarter results and exclude mark-to-market gains (losses) on risk management activities.

(2) 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		
($/boe) [1]	**Mar 31 2007**	Dec 31 2006	Mar 31 2006
Sales price [2]	**$ 49.32**	$ 43.91	$ 46.30
Royalties	**6.76**	5.62	6.44
Production expense [3]	**10.10**	9.16	8.46
Netback	**32.46**	29.13	31.40
Midstream contribution [3]	**(0.24)**	(0.22)	(0.25)
Administration	**1.08**	1.01	0.85
Interest, net	**1.49**	1.08	0.51
Realized risk management (gain) loss	**(1.58)**	2.25	7.90
Realized foreign exchange loss (gain)	**0.10**	(0.34)	(0.12)
Taxes other than income tax - current	**1.18**	0.78	0.71
Current income tax - North America	**0.45**	0.91	0.36
Current income tax - North Sea	**0.62**	0.54	0.01
Current income tax - Offshore West Africa	**0.18**	0.24	0.27
Cash flow	**$ 29.18**	$ 22.88	$ 21.16

(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 2007**		Dec 31 2006
ASSETS				
Current assets				
Cash and cash equivalents	**$**	**14**	$	23
Accounts receivable and other		**1,912**		1,947
Future income tax		**253**		163
Current portion of other long-term assets (note 3)		**36**		106
		2,215		2,239
Property, plant and equipment (note 12)		**32,036**		30,767
Other long-term assets (note 3)		**64**		154
	$	**34,315**	$	33,160
LIABILITIES				
Current liabilities				
Accounts payable	**$**	**648**	$	842
Accrued liabilities		**1,878**		1,618
Current portion of other long-term liabilities (note 5)		**793**		611
		3,319		3,071
Long-term debt (note 4)		**11,307**		11,043
Other long-term liabilities (note 5)		**1,590**		1,393
Future income tax		**7,135**		6,963
		23,351		22,470
SHAREHOLDERS' EQUITY				
Share capital (note 7)		**2,635**		2,562
Retained earnings		**8,374**		8,141
Accumulated other comprehensive loss (note 8)		**(45)**		(13)
		10,964		10,690
	$	**34,315**	$	33,160

Commitments (note 11)

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended **Mar 31 2007**	Mar 31 2006
Revenue	**$ 3,118**	$ 2,668
Less: royalties	**(376)**	(316)
Revenue, net of royalties	**2,742**	2,352
Expenses		
Production	**565**	419
Transportation and blending	**359**	377
Depletion, depreciation and amortization	**709**	521
Asset retirement obligation accretion (note 5)	**18**	17
Administration	**60**	42
Stock-based compensation (note 5)	**25**	132
Interest, net	**83**	25
Risk management activities (notes 2 and 10)	**448**	396
Foreign exchange (gain) loss (note 2)	**(27)**	5
	2,240	1,934
Earnings before taxes	**502**	418
Taxes other than income tax	**63**	61
Current income tax (note 6)	**70**	32
Future income tax (notes 2 and 6)	**100**	268
Net earnings	**$ 269**	$ 57
Net earnings per common share (note 9)		
Basic and diluted	**$ 0.50**	$ 0.11

Consolidated statements of shareholders' equity

(millions of Canadian dollars, unaudited)	Three Months Ended **Mar 31 2007**	Mar 31 2006
Common shares		
Balance – beginning of period	**$ 2,562**	$ 2,442
Issued upon exercise of stock options	**13**	10
Previously recognized liability on stock options exercised for common shares	**60**	48
Balance – end of period	**2,635**	2,500
Retained earnings		
Balance – beginning of period, as originally reported	**8,141**	5,804
Transition adjustment on adoption of financial instruments standards (note 2)	**10**	-
Balance – beginning of period, as restated	**8,151**	5,804
Net earnings	**269**	57
Dividends on common shares (note 7)	**(46)**	(40)
Balance – end of period	**8,374**	5,821
Accumulated other comprehensive loss (note 2)		
Balance – beginning of period	**(13)**	(9)
Transition adjustment on adoption of financial instruments standards	**159**	-
Balance – beginning of period, after effect of transition adjustment	**146**	(9)
Other comprehensive loss, net of taxes	**(191)**	(2)
Balance – end of period	**(45)**	(11)
Shareholders' equity	**$ 10,964**	$ 8,310

Consolidated statements of comprehensive income

(millions of Canadian dollars, unaudited)	Three Months Ended **Mar 31 2007**	Mar 31 2006
Net earnings	**$ 269**	$ 57
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized loss during the period (net of taxes of $55 million)	**(116)**	-
Reclassification to net earnings (net of taxes of $35 million)	**(74)**	-
	(190)	-
Foreign currency translation adjustment		
Translation of net investment	**(1)**	(2)
	(1)	(2)
Other comprehensive loss, net of taxes	**(191)**	(2)
Comprehensive income	**$ 78**	$ 55

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2007	Mar 31 2006
Operating activities		
Net earnings	**$ 269**	$ 57
Non-cash items		
Depletion, depreciation and amortization	**709**	521
Asset retirement obligation accretion	**18**	17
Stock-based compensation	**25**	132
Unrealized risk management activities	**536**	8
Unrealized foreign exchange (gain) loss	**(32)**	10
Deferred petroleum revenue tax (recovery) expense	**(3)**	26
Future income tax	**100**	268
Deferred charges	**(13)**	(15)
Abandonment expenditures	**(20)**	(15)
Net change in non-cash working capital	**(119)**	(311)
	1,470	698
Financing activities		
(Repayment) issue of bank credit facilities	**(2,013)**	619
(Repayment) issue of medium-term notes	**(125)**	400
Issue of US dollar debt securities	**2,553**	-
Issue of common shares on exercise of stock options	**13**	10
Dividends on common shares	**(40)**	(32)
Net change in non-cash working capital	**(22)**	2
	366	999
Investing activities		
Expenditures on property, plant and equipment	**(1,993)**	(2,294)
Net proceeds on sale of property, plant and equipment	**4**	-
Net expenditures on property, plant and equipment	**(1,989)**	(2,294)
Net change in non-cash working capital	**144**	591
	(1,845)	(1,703)
Decrease in cash and cash equivalents	**(9)**	(6)
Cash and cash equivalents – beginning of period	**23**	18
Cash and cash equivalents – end of period	**$ 14**	$ 12
Interest paid	**$ 158**	$ 52
Taxes paid		
Taxes other than income tax	**$ 35**	$ 81
Current income tax	**$ 71**	$ 173

Notes to the consolidated financial statements (tabular amounts in millions of Canadian dollars, 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, 2006, 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 financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2006.

Comparative figures

Certain figures relating to the presentation of gross revenues and gross transportation and blending provided for the prior year have been reclassified to conform to the presentation adopted in the fourth quarter of 2006.

2. CHANGE IN ACCOUNTING POLICY

Financial Instruments and Comprehensive Income

Effective January 1, 2007, the Company adopted the following new accounting standards issued by the Canadian Institute of Chartered Accountants relating to the accounting for and disclosure of financial instruments and comprehensive income:

- Section 1530 – "Comprehensive Income" introduces the concept of comprehensive income to Canadian GAAP. Comprehensive income is the change in equity (net assets) of the Company during a reporting period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. The foreign currency translation adjustment, which was previously a separate component of shareholders' equity, is now recorded as part of accumulated other comprehensive income.

- Section 3251 – "Equity" replaces Section 3250 – "Surplus" and establishes standards for the presentation of equity and changes in equity during a reporting period.

- Section 3855 – "Financial Instruments – Recognition and Measurement" prescribes when a financial asset, financial liability, or non-financial derivative should be recognized on the balance sheet as well as its measurement amount. This section also specifies how financial instruments gains and losses are to be presented.

- Section 3865 – "Hedges" replaces Accounting Guideline 13 – "Hedging Relationships" and EIC 128 – "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments" and specifies how hedge accounting is to be applied and what disclosures are necessary when hedge accounting is applied.

Adoption of these standards required the Company to record all of its derivative financial instruments on the balance sheet at estimated fair value as at January 1, 2007, including those designated as hedges. Designated hedges, other than cross currency interest rate swaps, were previously not recognized on the balance sheet but were disclosed in the notes to the financial statements. The adjustment to recognize the designated hedges on the balance sheet was recorded as an adjustment to the opening balance of retained earnings or accumulated other comprehensive income, as appropriate.

With the exception of the foreign currency translation adjustment, these standards were adopted prospectively; accordingly, comparative amounts for prior periods have not been restated. The reclassification of the foreign currency translation adjustment to other comprehensive income was applied retroactively with prior period restatement.

Effective January 1, 2007, the Company's accounting policies for financial instruments and comprehensive income are as follows:

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.

All derivative financial instruments are recognized at estimated fair value on the consolidated balance sheet at each balance sheet date. The estimated fair value of derivative instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. However, these 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 Company formally documents all derivative financial instruments designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in consolidated net earnings in the same period or periods in which the crude oil or natural gas is sold. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in consolidated net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in consolidated net earnings.

The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are included in interest expense in consolidated net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in consolidated net earnings.

Cross currency swap contracts are periodically used 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. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges are included in foreign exchange in consolidated net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in consolidated net earnings.

Gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income on the consolidated balance sheets and amortized into consolidated net earnings in the period in which the underlying hedged item is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in consolidated net earnings. Gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability and original issue discounts on long-term debt have been included in the carrying value of the financial asset or liability and are amortized to consolidated net earnings over the life of the financial instrument using the effective interest method.

Comprehensive Income

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses on the net investment in self-sustaining foreign operations. Other comprehensive income is shown net of related income taxes.

The effects of adopting these standards on the opening balance sheet were as follows:

		Jan 1, 2007
Increased current portion of other long-term assets (1)	$	193
Decreased other long-term assets (2)	$	(16)
Decreased long-term debt (3)	$	(72)
Increased retained earnings (4)	$	10
Increased foreign currency translation adjustment (5)	$	13
Increased accumulated other comprehensive income (6)	$	146
Decreased current portion of future income tax asset (7)	$	(62)
Increased future income tax liability (7)	$	18

(1) Relates to the recognition of the current portion of the fair value of derivative financial instruments designated as cash flow hedges.

(2) Relates to the recognition of the long-term portion of the fair value of derivative financial instruments designated as cash flow and fair value hedges, as well as the reclassification of transaction costs and original issue discounts from deferred charges to long-term debt.

(3) Relates to the fair value impact of derivative financial instruments designated as fair value hedges, as well as the reclassification of transaction costs and original issue discounts.

(4) Relates to the impact on adoption of the measurement of ineffectiveness on derivative financial instruments designated as cash flow hedges.

(5) Relates to the retroactive restatement of foreign currency translation adjustment to accumulated other comprehensive income.

(6) Relates to the recognition of accumulated other comprehensive income arising from the measurement of effectiveness on derivative financial instruments designated as cash flow hedges.

(7) Relates to the future income tax impacts of the above noted adjustments.

3. OTHER LONG–TERM ASSETS

		Mar 31 2007		Dec 31 2006
Deferred charges (note 2)	**$**	**78**	$	109
Risk management (note 10)		**-**		128
Other		**22**		23
		100		260
Less: current portion		**36**		106
	$	**64**	$	154

4. LONG–TERM DEBT

	Mar 31 2007	Dec 31 2006
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	**$ 4,608**	$ 6,621
Medium-term notes	**800**	925
	5,408	7,546
US dollar denominated debt		
Senior unsecured notes (2007 and 2006 - US$93 million)	**107**	108
US dollar debt securities (2007 - US$5,108 million; and 2006 - US$2,908 million)	**5,889**	3,389
Less – original issue discount on senior unsecured notes and US dollar debt securities (1)	**(23)**	-
	5,973	3,497
Change in fair value of interest rate swaps on US dollar debt securities (2)	**(22)**	-
	5,951	3,497
Long-term debt before transaction costs	**11,359**	11,043
Less – transaction costs (1) (3)	**(52)**	-
	$ 11,307	$ 11,043

(1) As described in note 2, effective January 1, 2007, 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 $22 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, 2007, the Company had in place unsecured bank credit facilities of $6,309 million, comprised of:

- a $100 million demand credit facility;
- a $500 million demand credit facility;
- a 3-year non-revolving syndicated credit facility of $2,350 million;
- a 5-year revolving syndicated credit facility of $1,825 million;
- a 5-year revolving syndicated credit facility of $1,500 million; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities mature June 2011. Both 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 conjunction with the closing of the acquisition of Anadarko Canada Corporation in November 2006, the Company executed a $3,850 million, three-year non-revolving syndicated credit facility maturing in October 2009. In March 2007, $1,500 million was repaid, reducing the facility to $2,350 million.

The weighted average interest rate of the bank credit facilities outstanding at March 31, 2007, was 4.8% (December 31, 2006 - 4.8%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $345 million, including $300 million related to the Horizon Project, were outstanding at March 31, 2007.

Medium-term notes

During the first quarter of 2007, $125 million of 7.40% unsecured debentures due March 1, 2007 were repaid.

The Company has $1,600 million remaining on its $2,000 million shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

US dollar debt securities

In March 2007, the Company issued US$2,200 million of unsecured notes under the US shelf prospectus, comprised of US$1,100 million of unsecured notes maturing May 2017 and US$1,100 million of unsecured notes maturing March 2038, bearing interest at 5.70% and 6.25%, respectively. Concurrently, the Company entered into cross currency interest rate swaps to fix the Canadian dollar interest and principal repayment amounts on the entire US$1,100 million of unsecured notes due May 2017 at 5.10% and C$1,287 million (note 10). The Company also entered into a cross currency interest rate swap to fix the Canadian dollar interest and principal repayment amounts on US$550 million of unsecured notes due March 2038 at 5.76% and C$644 million (note 10). 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$100 million remaining on its outstanding US$3,000 million shelf prospectus that allows for the issue of US dollar debt securities in the United States until July 2007. If issued, these securities will bear interest as determined at the date of issuance.

During the first quarter of 2007, the Company de-designated the portion of the US dollar denominated debt previously hedged against its net investment in US dollar based self-sustaining foreign operations. Accordingly, all foreign exchange (gains) losses arising each period on U.S. dollar denominated long-term debt are now recognized in the consolidated statement of earnings.

5. OTHER LONG–TERM LIABILITIES

	Mar 31 2007	Dec 31 2006
Asset retirement obligations	**$ 1,163**	$ 1,166
Stock-based compensation	**582**	744
Risk management (note 10)	**535**	-
Other	**103**	94
	2,383	2,004
Less: current portion	**793**	611
	$ 1,590	$ 1,393

Asset retirement obligations

At March 31, 2007, the Company's total estimated cost to settle its asset retirement obligations was approximately $4,508 million (December 31, 2006 - $4,497 million). These costs will be incurred over the lives of the operating assets and have been discounted using an average credit-adjusted risk free rate of 6.7%. A reconciliation of the discounted asset retirement obligations is as follows:

	Three Months Ended Mar 31, 2007	Year Ended Dec 31, 2006
Balance – beginning of period	**$ 1,166**	$ 1,112
Liabilities incurred	**5**	26
Liabilities acquired	**-**	56
Liabilities settled	**(20)**	(75)
Asset retirement obligation accretion	**18**	68
Revision of estimates	**-**	(21)
Foreign exchange	**(6)**	-
Balance – end of period	**$ 1,163**	$ 1,166

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 12-month period if all vested options are surrendered for cash settlement.

	Three Months Ended Mar 31, 2007	Year Ended Dec 31, 2006
Balance – beginning of period	**$ 744**	$ 891
Stock-based compensation	**25**	139
Current period payment for options surrendered	**(136)**	(264)
Transferred to common shares	**(60)**	(101)
Capitalized to Horizon Project	**9**	79
Balance – end of period	**582**	744
Less: current portion of stock-based compensation	**419**	611
	$ 163	$ 133

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended	
	Mar 31 2007	Mar 31 2006
Current income tax – North America	**$ 25**	$ 18
Current income tax – North Sea	**35**	1
Current income tax – Offshore West Africa	**10**	13
Current income tax	**70**	32
Future income tax	**100**	268
Income tax expense	**$ 170**	$ 300

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 and amount of capital expenditures incurred in Canada in any particular year.

During the first quarter of 2006, income tax rate changes resulted in an increase of future income tax liabilities of approximately $110 million in the UK North Sea.

7. SHARE CAPITAL

	Three Months Ended Mar 31, 2007	
Issued **Common shares**	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**537,903**	**$ 2,562**
Issued upon exercise of stock options	**1,278**	**13**
Previously recognized liability on stock options exercised for common shares	**-**	**60**
Balance – end of period	**539,181**	**$ 2,635**

Normal Course Issuer Bid

In January 2007, the Company renewed its Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12-month period beginning January 24, 2007 and ending January 23, 2008, up to 26,941,730 common shares or 5% of the outstanding common shares of the Company then outstanding on the date of the announcement. As at March 31, 2007, the Company had not purchased any shares under the Normal Course Issuer Bid.

Dividend policy

In March 2007, the Board of Directors set the regular quarterly dividend at $0.085 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, 2007		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**34,425**	**$**	**33.77**
Granted	**482**	**$**	**60.63**
Exercised for common shares	**(1,278)**	**$**	**10.47**
Surrendered for cash settlement	**(2,913)**	**$**	**13.78**
Forfeited	**(629)**	**$**	**45.75**
Outstanding – end of period	**30,087**	**$**	**36.90**
Exercisable – end of period	**9,034**	**$**	**20.91**

8. ACCUMULATED OTHER COMPREHENSIVE LOSS

The components of accumulated other comprehensive loss were as follows:

	Three Months Ended			
		Mar 31 2007		Mar 31 2006
Derivative financial instruments designated as cash flow hedges	**$**	**(31)**	$	-
Foreign currency translation adjustment		**(14)**		(11)
Accumulated other comprehensive loss	**$**	**(45)**	$	(11)

9. NET EARNINGS PER COMMON SHARE

	Three Months Ended			
		Mar 31 2007		Mar 31 2006
Weighted average common shares outstanding (thousands) – basic and diluted		**538,890**		537,227
Net earnings – basic and diluted	**$**	**269**	$	57
Net earnings per common share – basic and diluted	**$**	**0.50**	$	0.11

10. FINANCIAL INSTRUMENTS

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.

As described in note 2, commencing January 1, 2007, the Company recorded all of its derivative financial instruments on the balance sheet at fair value, including those designated as hedges. As at December 31, 2006, the net unrecognized asset related to the estimated fair values of derivative financial instruments designated as hedges was $222 million.

The estimated fair values of financial derivatives recognized in the risk management asset (liability) were comprised as follows:

	Three Months Ended Mar 31, 2007	Year Ended Dec 31, 2006	
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market	Deferred revenue
Balance – beginning of period, as originally stated	**$ 128**	$ (877)	$ (8)
Retained earnings effect of adoption of financial instrument standards (note 2)	**14**	-	-
Net cost of outstanding put options	**318**	455	-
Net change in fair value of outstanding derivative financial instruments attributable to:			
- Risk management activities	**(536)**	995	-
- Interest expense	**(22)**	-	-
- Foreign exchange	**(37)**	10	-
- Other comprehensive income	**(46)**	-	-
Amortization of deferred revenue	**-**	-	8
	(181)	583	-
Add: Put premium financing obligations [(1)]	**(354)**	(455)	-
Balance – end of period	**(535)**	128	-
Less: current portion	**(374)**	88	-
	$ (161)	$ 40	$ -

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

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

	Three Months Ended Mar 31 2007	Mar 31 2006
Net realized risk management (gain) loss	**$ (88)**	$ 388
Net unrealized risk management loss	**536**	8
	$ 448	$ 396

The Company had the following net financial derivatives outstanding as at March 31, 2007:

	Remaining term			Volume	Average price			Index
Crude oil								
Crude oil price collars [(1)]	Apr 2007	–	Dec 2007	15,000 bbl/d	US$50.00	–	US$66.25	Mayan Heavy
	Apr 2007	–	Dec 2007	50,000 bbl/d	US$60.00	–	US$71.49	WTI
	Apr 2007	–	Dec 2007	100,000 bbl/d	US$60.00	–	US$78.11	WTI
	Apr 2007	–	Dec 2007	50,000 bbl/d	US$65.00	–	US$84.52	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$75.22	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.05	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d	US$60.00	–	US$76.98	WTI
Crude oil puts	Apr 2007	–	Dec 2007	100,000 bbl/d			US$45.00	WTI
	Apr 2007	–	Dec 2007	77,000 bbl/d			US$60.00	WTI
	Jan 2008	–	Dec 2008	50,000 bbl/d			US$55.00	WTI
Brent differential swaps	Apr 2007	–	Dec 2007	50,000 bbl/d			US$1.34	WTI/Dated Brent

(1) Subsequent to March 31, 2007, the Company entered into 50,000 bbl/d of US$60.00 – US$80.06 WTI collars for the period January 2008 to March 2008.

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

	Q2 2007	Q3 2007	Q4 2007	Q1 2008	Q2 2008	Q3 2008	Q4 2008
Cost ($ millions)	US$71	US$72	US$72	US$14	US$15	US$15	US$15

	Remaining term			Volume	Average price			Index
Natural gas								
AECO collars	Apr 2007	–	Dec 2007	60,000 GJ/d	C$8.00	–	C$8.79	AECO
	Apr 2007	–	Oct 2007	500,000 GJ/d	C$6.00	–	C$10.13	AECO
	Apr 2007	–	Oct 2007	500,000 GJ/d	C$7.00	–	C$8.24	AECO
	Nov 2007	–	Mar 2008	400,000 GJ/d	C$7.00	–	C$14.08	AECO
	Nov 2007	–	Mar 2008	500,000 GJ/d	C$7.50	–	C$10.81	AECO

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

In addition to the financial derivatives noted above, the Company also entered into natural gas physical sales contracts for 300,000 GJ/d at an average fixed price of C$7.33 per GJ at AECO for the period April 2007 to October 2007.

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Apr 2007	–	Oct 2012	US$350	5.45%	LIBOR (1) + 0.81%
	Apr 2007	–	Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%

(1) London Interbank Offered Rate

	Remaining term			Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Apr 2007	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Apr 2007	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Apr 2007	–	Mar 2038	US$550	1.170	6.25%	5.76%

11. COMMITMENTS

The Company has committed to certain payments as follows:

	Remaining 2007	2008	2009	2010	2011	Thereafter
Product transportation and pipeline (1)	$ 172	$ 198	$ 135	$ 123	$ 95	$ 1,043
Offshore equipment operating leases (2)	$ 79	$ 53	$ 52	$ 52	$ 50	$ 132
Offshore drilling (3)	$ 48	$ 83	$ 12	$ 12	$ 7	$ -
Asset retirement obligations (4)	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4,491
Office leases	$ 24	$ 34	$ 34	$ 36	$ 23	$ -
Electricity and other	$ 40	$ 11	$ 18	$ 18	$ 1	$ -

(1) The Company entered into a 25-year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, the annual toll payments before operating costs will be approximately $35 million.

(2) 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. The new FPSO lease agreement contains cancellation provisions at the option of the Company, subject to escalating termination payments throughout 2007 to a maximum of US$395 million.

(3) Subsequent to March 31, 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 to commence in the fourth quarter of 2007, subject to rig availability, with minimum payments estimated to be US$160 million, before joint venture recoveries.

(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 2007 – 2011 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

In 2005, the Board of Directors of the Company approved the construction costs for Phase 1 of the Horizon Project, with an approved budget of $6.8 billion. Cumulative construction spending to March 31, 2007 was approximately $4.7 billion. Final construction costs for Phase 1 are expected to exceed the approved budget primarily due to inflationary cost pressures.

12. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America Three Months Ended Mar 31 **2007**	 2006	North Sea Three Months Ended Mar 31 **2007**	 2006	Offshore West Africa Three Months Ended Mar 31 **2007**	 2006
Segmented revenue	**2,535**	2,116	**431**	320	**144**	227
Less: royalties	**(366)**	(310)	**(1)**	(1)	**(9)**	(5)
Segmented revenue, net of royalties	**2,169**	1,806	**430**	319	**135**	222
Segmented expenses						
Production	**422**	312	**116**	81	**22**	22
Transportation and blending	**365**	384	**4**	3	**-**	-
Depletion, depreciation and amortization	**560**	415	**107**	60	**40**	44
Asset retirement obligation accretion	**9**	8	**8**	8	**1**	1
Realized risk management activities	**(92)**	317	**4**	71	**-**	-
Total segmented expenses	**1,264**	1,436	**239**	223	**63**	67
Segmented earnings (loss) before the following	**905**	370	**191**	96	**72**	155
Non-segmented expenses						
Administration						
Stock-based compensation						
Interest, net						
Unrealized risk management activities						
Foreign exchange (gain) loss						
Total non-segmented expenses						
Earnings before taxes						
Taxes other than income tax						
Current income tax						
Future income tax						
Net earnings						

(millions of Canadian dollars, unaudited)	Midstream Three Months Ended Mar 31 **2007**	 2006	Inter-segment elimination and other Three Months Ended Mar 31 **2007**	 2006	Total Three Months Ended Mar 31 **2007**	 2006
Segmented revenue	**19**	18	**(11)**	(13)	**3,118**	2,668
Less: royalties	**-**	-	**-**	-	**(376)**	(316)
Segmented revenue, net of royalties	**19**	18	**(11)**	(13)	**2,742**	2,352
Segmented expenses						
Production	**6**	5	**(1)**	(1)	**565**	419
Transportation and blending	**-**	-	**(10)**	(10)	**359**	377
Depletion, depreciation and amortization	**2**	2	**-**	-	**709**	521
Asset retirement obligation accretion	**-**	-	**-**	-	**18**	17
Realized risk management activities	**-**	-	**-**	-	**(88)**	388
Total segmented expenses	**8**	7	**(11)**	(11)	**1,563**	1,722
Segmented earnings (loss) before the following	**11**	11	**-**	(2)	**1,179**	630
Non-segmented expenses						
Administration					**60**	42
Stock-based compensation					**25**	132
Interest, net					**83**	25
Unrealized risk management activities					**536**	8
Foreign exchange (gain) loss					**(27)**	5
Total non-segmented expenses					**677**	212
Earnings before taxes					**502**	418
Taxes other than income tax					**63**	61
Current income tax					**70**	32
Future income tax					**100**	268
Net earnings					**269**	57

Net additions to property, plant and equipment

	Three Months Ended					
	Mar 31, 2007			Mar 31, 2006		
	Net Cash Expenditures	**Non-Cash/ Fair Value Changes (1)**	**Capitalized Costs**	Net Cash Expenditures	Non-Cash/ Fair Value Changes (1)	Capitalized Costs
North America	**$ 998**	**$ 5**	**$ 1,003**	$ 1,404	$ 5	$ 1,409
North Sea	**138**	**-**	**138**	138	-	138
Offshore West Africa	**36**	**-**	**36**	50	-	50
Other	**1**	**-**	**1**	7	-	7
Horizon Project (2)	**809**	**-**	**809**	686	-	686
Midstream	**2**	**-**	**2**	3	-	3
Head office	**5**	**-**	**5**	6	-	6
	$ 1,989	**$ 5**	**$ 1,994**	$ 2,294	$ 5	$ 2,299

(1) Asset retirement obligations, future income tax adjustments on non-tax base assets, and other fair value adjustments.

(2) Cash expenditures for the Horizon Project also include capitalized interest and stock-based compensation.

	Property, plant and equipment		Total assets	
	Mar 31 2007	Dec 31 2006	**Mar 31 2007**	Dec 31 2006
Segmented assets				
North America	**$ 22,324**	$ 21,879	**$ 24,027**	$ 23,670
North Sea	**2,049**	2,029	**2,298**	2,248
Offshore West Africa	**1,197**	1,204	**1,308**	1,323
Other	**26**	24	**28**	46
Horizon Project	**6,159**	5,350	**6,251**	5,444
Midstream	**207**	207	**329**	355
Head office	**74**	74	**74**	74
	$ 32,036	$ 30,767	**$ 34,315**	$ 33,160

Capitalized interest

Beginning in 2005, following the Board of Directors' approval of the Horizon Project, the Company commenced capitalization of construction period interest based on costs incurred and the Company's cost of borrowing. Interest capitalization on Phase 1 will cease 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 $71 million was capitalized to the Horizon Project (March 31, 2006 - $33 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 August 2005. 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, 2007:	
Interest coverage (times)	
Net earnings [(1)]	8.5x
Cash flow from operations [(2)]	13.8x

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

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

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, May 3, 2007. The North American conference call number is 1-877-888-4483 and the outside North American conference call number is 001-416-695-9712. Please call in about 10 minutes before the starting time in order to be patched into the call. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time Thursday, May 10, 2007. To access the postview in North America, dial 1-888-509-0081. Those outside of North America, dial 001-416-695-5275. The passcode to use is 642008.

WEBCAST

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

The webcast is also being distributed over PrecisionIR's Investor Distribution Network to both institutional and individual investors. Investors can listen to the call through www.vcall.com or by visiting any of the investor sites in PrecisionIR's Individual Investor Network.

2007 SECOND QUARTER RESULTS

2007 second quarter results are scheduled for release on Thursday, August 2, 2007. A conference call will be held on that day at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time.

ANNUAL AND SPECIAL MEETING OF THE SHAREHOLDERS

Canadian Natural Resources Limited's Annual and Special Meeting of the Shareholders will be held on Thursday, May 3, 2007 at 3:00 p.m. Mountain Time at the Metropolitan Centre, Calgary, Alberta. All shareholders are invited to attend.

For further information, please contact:

CANADIAN NATURAL RESOURCES LIMITED

2500, 855 - 2nd Street S.W.

Calgary, Alberta

T2P 4J8

Telephone: (403) 514-7777
Facsimile: (403) 514-7888
Email: ir@cnrl.com
Website: www.cnrl.com

Trading Symbol - CNQ
Toronto Stock Exchange
New York Stock Exchange

ALLAN P. MARKIN
Chairman

JOHN G. LANGILLE
Vice-Chairman

STEVE W. LAUT
President &
Chief Operating Officer

DOUGLAS A. PROLL
Chief Financial Officer &
Senior Vice-President, Finance

COREY B. BIEBER
Vice-President,
Finance & Investor Relations