Canadian Natural

Press Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD FIRST HALF CASH FLOW WITH STRONG SECOND QUARTER RESULTS

CALGARY, ALBERTA – August 6, 2003 – FOR IMMEDIATE RELEASE

In commenting on second quarter 2003 results, Canadian Natural's President, John Langille, stated "Canadian Natural continues to execute its strategies with a high level of success. Our natural gas development program is on target, and signs point to a very successful exploitation program to be carried out in Northwest Alberta. Our heavy oil drilling program has ramped up and will result in production increases during the second half of the year. Internationally, we have also delivered production increases at Espoir and our exploitation successes in the North Sea have exceeded expectations as production levels were maintained even, as extensive maintenance work on the Ninian South Platform was completed to ensure the productive integrity of the Platform."

"First half cash flows have doubled over last year to a record $1.7 billion. As a result, our balance sheet continues to get stronger with debt to book capitalization decreasing to 35%. This is important as it enhances our ability to keep more of the Horizon Oil Sands Project for our shareholders. The Horizon Project has also benefited from good news, both in terms of setting a date for regulatory hearings and by recent public comments by the Federal Government, which go a long way to providing long-term certainty on how the Kyoto Protocol will be implemented after 2012."

"In another step that is responsive to evolving shareholder expectations and ongoing employee retention, we are pleased to announce changes in our stock option plan that result in the expensing of obligations under the plan with a corresponding favourable income tax deduction available to the Company. During the quarter, a charge of $72 million has been included in net earnings representing the total after-tax obligation of the stock option plan."

HIGHLIGHTS OF THE SECOND QUARTER

- Record net earnings of $525 million ($3.91 per common share) compared with $145 million ($1.18 per common share) for the second quarter of 2002 and $428 million ($3.19 per common share) in the previous quarter. Record first half earnings accumulated to $953 million, compared with $244 million in 2002.

- Record second quarter cash flow of $762 million ($5.68 per common share) compared with $475 million ($3.86 per common share) in the second quarter of 2002 and $906 million ($6.76 per common share) in the previous quarter. Record first half cash flows of $1.7 billion compared with $0.8 billion in 2002.

- Record second quarter natural gas sales of 1.3 billion cubic feet per day, representing 48% of equivalent production during the quarter.

- Record second quarter crude oil and NGLs sales of over 240 thousand barrels per day.

- Reduced long-term debt by $412 million during the quarter through repayments of $201 million and foreign exchange gains of $211 million resulting from the strengthening of the Canadian dollar. This reduced debt to book capitalization to 35%, compared with 46% at year end 2002 and 48% immediately following the acquisition of Rio Alto Exploration Ltd. on July 1, 2002.

- Net capital expenditures of $410 million reflected the ramp-up of the spring heavy oil drilling program, facilities work resulting from the winter natural gas drilling program and continued development of international properties. During the quarter, Canadian Natural drilled 224 wells, including 157 oil wells.

- During the three months ended June 30, 2003, the Company purchased 664,200 of its common shares for a total cost of $33 million. As of August 5, 2003, the Company had purchased approximately 1.4 million of its common shares for a total cost of $69 million under its Normal Course Issuer Bid.

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 for each of the periods reported. Adjusted net earnings from operations is a non-GAAP term that the Company utilizes to evaluate its performance and that of it business segments.

($ millions, except per common share amounts)

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Net earnings attributable to common shareholders as reported	**$ 525**	$ 428	$ 145	**$ 953**	$ 244
Unrealized foreign exchange gain [1]	**(87)**	(96)	(64)	**(183)**	(76)
Unrealized foreign exchange gain on preferred securities[1]	**(7)**	(7)	(6)	**(14)**	(6)
Effect of statutory tax rate changes on future income tax liabilities[2]	**(247)**	-	13	**(247)**	13
Stock-based compensation expense [3]	**72**	-	-	**72**	-
Reduction in carrying value of foreign assets[4]	**-**	-	30	**-**	30
Adjusted net earnings from operations attributable to common shareholders	**$ 256**	$ 325	$ 118	**$ 581**	$ 205
Per share – basic	**$ 1.91**	$ 2.42	$ 0.96	**$ 4.33**	$ 1.68
– diluted	**$ 1.88**	$ 2.34	$ 0.93	**$ 4.25**	$ 1.63

[1] *Gains and losses on the translation of long-term debt and preferred securities to period end exchange rates are immediately recognized in net earnings attributable to common shareholders. In 2002 the Company utilized previously unrecognized income tax benefits on capital losses to offset income taxes related to these gains.*

[2] *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 are recorded in net earnings during the period the legislation is substantively enacted. During the second quarter of 2003, the Canadian Government introduced several income tax changes, including rate reductions, for the resource industry. Also during the quarter, a Canadian province reduced corporate income tax rates. During the second quarter of 2002, the United Kingdom increased income taxes applicable to the oil and natural gas industry and a Canadian province reduced corporate income tax rates.*

[3] *During the second quarter of 2003, the Company modified its employee stock option plan to provide for a cash payment option. A charge of $72 million after taxes ($105 million before taxes) was recognized to represent the mark-to-market liability of the plan for all earned options as at June 30, 2003.*

[4] *Following an unsuccessful exploratory well on Block 19 in Angola and the decision to withdraw from an exploration block in Nigeria, all capitalized costs related to these projects were charged to net earnings.*

OPERATIONS REVIEW

Production

Natural gas production levels increased from the first quarter, reflecting the Company's extensive winter 2003 natural gas drilling program and despite continued production declines from the Ladyfern field. As a result of the winter drilling program, North American natural gas production, exclusive of the Ladyfern field, has increased from 1,189 mmcf/d during the previous quarter to 1,216 mmcf/d during the second quarter of 2003.

Crude oil and NGLs increased as the result of a ramp up in heavy oil drilling in western Canada and the perforation of upper zones at the Espoir field located in Côte d'Ivoire. North Sea production remained relatively constant with the previous quarter despite the extended shut in of production at the Ninian South Platform. This platform produces approximately 17,000 barrels per day of crude oil production for Canadian Natural and was shut in for 25 days during the second quarter. Initial production from new in-fill drilling at the Ninian field offset most of this unexpected downtime.

The Company's production composition is as follows:

	Q2 2003		Q1 2003		Q2 2002	
	mboe/d	**%**	mboe/d	%	mboe/d	%
Natural gas	**220.9**	**48**	218.4	48	179.6	49
Light crude oil and NGLs	**112.0**	**24**	112.6	25	70.1	19
Pelican Lake crude oil	**25.9**	**6**	25.1	5	30.8	8
Primary heavy crude oil	**63.8**	**14**	60.4	13	51.3	14
Thermal heavy crude oil	**38.9**	**8**	39.5	9	37.2	10
Total	**461.5**	**100**	456.0	100	369.0	100

The Energy Utilities Board ("EUB") in Alberta has recently announced the requirement to shut in certain natural gas production in North Alberta where there may be a risk of reduced future production of bitumen reserves. As a result of this order, Canadian Natural expects to shut in approximately 15 to 20 mmcf/d of natural gas production on September 1, 2003. A further 5 to 10 mmcf/d of natural gas production may be subject to shut in dependent upon resolution of appeals sought by the Company.

The Company expects production levels in 2003 to average 1,280 to 1,330 mmcf/d of natural gas and 240 to 260 mbbls/d of oil and liquids. Third quarter 2003 production guidance for natural gas is 1,278 to 1,302 mmcf/d of natural gas and 242 to 256 mbbls/d of oil and liquids. Third quarter natural gas decreases reflect lower seasonal drilling activity as well as regularly scheduled maintenance and the anticipated effect of the EUB order. Further detailed guidance on production levels and operating costs may be found on the Company's website (http://www.cnrl.com/investor/guidance.htm).

DRILLING ACTIVITY (number of wells)

	Six Months Ended June 30			
	2003		2002	
	Gross	**Net**	Gross	Net
Oil	**292**	**273**	223	193
Natural gas	**319**	**299**	136	123
Dry and abandoned	**31**	**30**	24	20
Subtotal	**642**	**602**	383	336
Stratigraphic test/service wells	**373**	**371**	415	407
Total	**1,015**	**973**	798	743
Success rate (excluding strat tests/service wells)		**95%**		94%

During the second quarter of 2003, Canadian Natural drilled 224 net wells, including 5 stratigraphic test and service wells. A total of 55 net natural gas wells were drilled, bringing the total for the first half of 2003 to 299 net wells, which represents an increase of 143% over the same period in 2002.

The Company also drilled 157 net oil wells during the second quarter, bringing the total for the first half to 273 net wells, which represents a 41% increase over the first half of 2002. These wells were concentrated in the Company's oil region of North Alberta where 126 primary heavy oil and 13 Pelican Lake wells were drilled. Six additional high-pressure horizontal thermal wells were also drilled and completed at Primrose as part of the 2003/2004 development strategy of the area.

Pricing

Product pricing remained strong during the second quarter for both crude oil and natural gas. Heavy oil differential percentages remained within a narrow band as a result of lower supply resulting from the first quarter political and crude oil production problems in Venezuela. Detailed reviews of benchmark pricing and Canadian Natural's realized prices are available in Management's Discussion and Analysis.

Canadian Natural's realized prices remain sensitive to currency exchange rates. The recent increases in the value of the Canadian dollar in relation to the United States dollar had a negative impact on commodity price realizations. Sensitivity to exchange rate changes and commodity prices are detailed in Management's Discussion and Analysis.

The Company utilizes hedges on a portion of its production in an effort to assure operating cash flows are sufficient to cover capital expenditures. Revised policies now allow for up to 50% of any one commodity to be hedged using cost-less collars for a period not exceeding 12 months, and no more than 25% of production can be hedged in a period beyond 12 months and less than 24 months. Previously, the Company only hedged as far as 12 months. The corporate hedging policies are reviewed on a regular basis and this revision reflects the transition of Canadian Natural's project portfolio to longer-term developments. This policy may be reviewed at a future date in anticipation of the significant scope of the Horizon Oil Sands Project. As at August 5, 2003, the Company had entered into second half commodity hedges covering approximately 4% and 44% of anticipated natural gas production and crude oil production, respectively.

Third quarter indicative prices as at August 5, 2003 reference a West Texas Intermediate price of US $32.22/barrel and a NYMEX natural gas price of US $4.68/mmbtu. The Lloyd Blend heavy oil differential was approximately US $8.50/barrel at this date.

ACTIVITY BY CORE REGION

	Net Undeveloped Land as at June 30, 2003	Drilling Activity six months ended June 30, 2003
	(thousands of net acres)	(net wells)
Northeast British Columbia	**1,469**	**86**
Northwest Alberta	**1,359**	**47**
North Alberta	**6,026**	**439**
South Alberta	**712**	**66**
Southeast Saskatchewan	**151**	**13**
Horizon Oil Sands Project	**117**	**312**
United Kingdom North Sea	**503**	**8**
Offshore West Africa	**943**	**2**
Total	**11,280**	**973**

North American Natural Gas

Canadian Natural's drilling program during the second quarter was highlighted by the start up of the summer shallow natural gas program (32 wells) in South Alberta. The Company anticipates the drilling of approximately 100 shallow natural gas wells and up to 70 conventional and deep natural gas wells during the third quarter.

Shallow natural gas programs in South Alberta, while integral to the Company's ongoing success, are not sufficient to offset normal production declines from winter access fields in other core regions; hence the Company is expecting lower third quarter volumes when compared with second quarter natural gas production levels. Successful deeper wells are expected to be in production by the fourth quarter, which offset normal production declines to a greater degree.

During the quarter, a regular review of the winter drilling program identified new opportunities to further reduce capital costs in the Northwest Alberta core natural gas region. This review also confirmed that these properties are performing as well as, and in some cases even better than, original expectations. Canadian Natural believes that its disciplined approach to the development of this area has resulted in a better knowledge of the geological targets and a better approach to exploitation. Technical data, production history and past drilling history are all being evaluated in an effort to better identify drilling targets and set up a more aggressive drilling program. The Company now believes that it is in a position to ramp up development of this area and expects to drill 55 to 60 wells during the second half of 2003 and up to 150 wells during 2004.

The revised royalty regime recently announced by the Government of British Columbia enhances the attractiveness of heretofore economically-marginal prospects in the Northeast British Columbia core region. As a result of this change, the Company now believes that several new shallow natural gas drilling prospects will be developed over time. Additionally, the Company is investigating opportunities to make areas of this and other core regions drilling accessible year round. Over the long term, such opportunities should reduce the seasonality of production peaks in future years.

North American Crude Oil and NGLs

Canadian Natural continues the disciplined development of its vast heavy oil resources. As has been previously articulated, these reserves will be developed as heavy oil markets permit. The Company is working with refiners to examine opportunities to expand heavy oil conversion capacity of refineries in the Midwest United States, and is working with pipeline companies to develop new capacity to the Canadian West Coast where crude cargos could be sold on a world-wide basis. Over the long term, as these opportunities come to fruition, Canadian Natural will accelerate development of its vast bitumen resources.

Canadian Natural's drilling program during the second quarter was concentrated on heavy oil (126 wells) and Pelican Lake oil (13 wells) in North Alberta. The Company anticipates the drilling of approximately 110 heavy oil wells during the third quarter. Given the normal production profile of new heavy oil wells as well as continued drilling expectations, it is anticipated that production volumes will increase during the second half.

As an integral part of the long-term heavy oil strategy mentioned above, the Company's Primrose expansion continues on budget with six new thermal wells being drilled during the second quarter. A further 18 wells will be drilled during the second half of 2003, with steaming to commence late in 2003. First production from these new wells will commence in mid-2004.

The Enhanced Oil Recovery project at Pelican Lake continues with a new waterflood test program. The emulsion flood test was very successful from a technical perspective, pushing recoverability of reserves well above the current 6% achieved under primary production methods. However, response time was too slow to be economic. The current waterflood test will seek to increase the speed of response, albeit likely at lower recovery factors than the previous emulsion flood. Opportunities also exist to use the conventional waterflood program in conjunction with the emulsion technologies to maximize value creation through the balancing of recovery factor with timely response.

North America Horizon Oil Sands Project

During the second quarter of 2003, engineering work on the Horizon Oil Sands Project ("Horizon Project") continued towards completion of the Design Basis Memorandum ("DBM") phase of engineering. Completion of the DBM was achieved in July and the Engineering Design Specification ("EDS") phase has commenced. Work on a new 30 kilometre access road, including three bridges, also continues. A date for a joint panel review of the project by the Alberta EUB and Fisheries and Oceans Canada is scheduled to commence on September 15, 2003. The Company believes that this joint panel, a first for the industry, will lead to a streamlined Government approval process.

With respect to the Kyoto Protocol, public comments on post-2012 principles recently made by the Prime Minister and the Federal Government provided a very positive step toward being able to better determine the impact of the Kyoto Protocol over the life of this 50-year project. While still under evaluation, management of the Company has increased optimism that this international treaty will not be a determining factor in final Board of Directors approval for the project.

The most significant determining factor for approval will now be capital costs to construct. Canadian Natural has been refining detailed cost reviews throughout the DBM phase of engineering. Canadian Natural recognizes cost pressures exist, however, it has utilized conservative cost estimating practices and completed extensive benchmarking to actual field costs throughout the DBM engineering phase. The Company expects to have final cost estimates at the end of the DBM phase that are not materially different from the original estimate of $4.9 billion for phase one production and $8.5 billion for the full three-phase development resulting in production of 232,000 barrels per day of light synthetic crude oil.

The financing of the first phase of development will be guided by the competing principles of retaining as much direct ownership interest as possible while maintaining our current strong debt ratings and not issuing additional equity in common shares. Canadian Natural is also investigating the use of long-term commodity hedges in order to reduce cash flow risks during the construction phase. Should debt ratings come under severe pressure, the Company would look to offload capital commitments through the acceptance of complementary business partners, or potentially, project equity partners. Recent commodity price increases have significantly strengthened the balance sheet of the Company, placing it in a better position to achieve both of its guiding principles.

The Company currently employs 73 full time employees and 111 full time contractors on this project and expects this to double as the EDS continues in the fall. The members of this team are very experienced in all facets of oil sands construction and operations.

United Kingdom

Canadian Natural remains excited about the prospects of extracting additional value from the oil fields surrounding the Ninian and Murchison platforms. During the second quarter, the Company drilled three oil wells and one water injector well targeting unswept oil reserves within the Ninian, Murchison and Columba fields. In addition, a number of productive wells were re-entered to access behind pipe reserves. These wells provided average rates of 5,200 bbls/d of oil with significant higher initial rates. Initial production levels from these wells enabled the Company to produce at levels similar to the first quarter despite the shut in of 17,000 bbls/d of production for 25 days at the Ninian South Platform. These results follow a successful first quarter program and continue to indicate the potential of the field redevelopment program initiated by Canadian Natural.

Early in the third quarter of 2003, the Company further consolidated ownership interests to 87.6% in the Banff Field located in the Central North Sea. The Company acquired approximately 4,500 bbls/d of production via an additional 31.7% working interest and assumed operatorship of the Banff Field and Block 29/2a, all subject to partner and Government approval. Canadian Natural now operates 99% of its North Sea production and maintains an average ownership interest of about 80% in its properties.

In late July 2003, Canadian Natural was the successful bidder on 6 new exploration licenses at the UK Governments' 21st Seaward Licensing Round. These Blocks provide for additional exploration lands adjacent to the Ninian hub in the Northern North Sea.

Offshore West Africa

During the second quarter Canadian Natural perforated the upper zone of the East Espoir structure, increasing Canadian Natural's share of production to approximately 14,000 barrels of oil equivalent per day. The Company recently completed the fourth water injection well and is drilling an additional production well in order to maintain similar production through the remainder of 2003. Development plans for the West Espoir structure are currently being evaluated, with potential for mid-2004 production.

During the second quarter the successful drilling of the satellite pool, Acajou, was completed. The Acajou 1X well was production tested at gross rates of 3,500 bbls/d. The productive, oil-bearing sands encountered in the 1X well are thin; however, additional sands, which hold significant potential on the northern portion of the structure, were encountered. After the reprocessing of seismic and analysis of the 1X test well is completed, Canadian Natural will evaluate drilling the northern portion of Acajou.

Also during the quarter Canadian Natural awarded three major contracts for the development of the Baobab Field. The Baobab Field, located on Block CI-40 25km offshore Côte d'Ivoire, has estimated recoverable reserves of 200 million barrels of 23 degree API oil. Canadian Natural is the operator with a 57.61% equity interest in Block CI-40. Hydrocarbons will be delivered from subsea well clusters to a Floating Production, Storage and Offtake ("FPSO") vessel with a storage capacity of 2 million barrels. Oil production, which is expected to commence in the second quarter of 2005 at approximately 45,000 bbls/d and subsequently peak at 60,000 bbls/d, will be sold directly from the FPSO, with the associated natural gas being transported to shore via the Espoir Field infrastructure.

Finally, Canadian Natural continued to reprocess seismic on Block 16 located offshore Angola to optimize the locations for potential drilling on two separate, significant structures - Zenza and Omba. Based on the results of the seismic reprocessing and the results of nearby drilling completed in Block 32 by another operator, the Company will drill one of the two structures in the fourth quarter, subject to partner approval. The Zenza prospect is located in 1,000 metres of water with a total drilling depth of 4,000 metres. Block 16, where the Company operates with a 50% working interest, represents a high risk/high impact exploration development for the Company in one of the most prolific oil regions of the world.

FINANCIAL REVIEW

Canadian Natural recognizes the need for a strong financial position in order to withstand volatile oil and natural gas commodity prices and the operational risks inherent in the oil and natural gas business environment.

During the first half of 2003, strong operational results and product pricing enabled the Company to repay approximately $600 million of long-term debt. The strength of the Canadian dollar during the half also reduced carrying values of US dollar based borrowings by an additional $400 million, resulting in a total decrease of long-term debt of $1.0 billion. Corporate debt to cash flow was reduced to 1.0 times versus 1.8 times at December 31, 2002, while debt to book capitalization improved to 35% from 46% at year-end 2002.

Continuing higher than budgeted prices received for the Company's products are expected to result in increased cash flow to the Company in 2003 over the capital budget established in late 2002. The Company will monitor its expected cash flow surplus and at present intends to allocate a minimum of 50% of such amounts toward debt repayment. The remaining excess will be directed to the Company's authorized share buy-back program and additional expenditures on conventional oil and natural gas opportunities. Such expenditures will only be incurred as excess cash flows are realized and will be subject to the same economic tests as regular budgeted expenditures. It is expected that the largest portion of the additional capital expenditures will take place late in the third and fourth quarters of 2003 and accordingly will not add materially to Canadian Natural's 2003 average production volumes. Should additional economic opportunities for share buy-backs or capital activities not materialize, such allocations of excess cash flow would revert to debt repayment. To date, 1.4 million common shares have been purchased for cancellation in 2003 under the Normal Course Issuer Bid.

In June, the Board of Directors approved certain amendments to the Company's stock option plan introducing a cash payment alternative to be included both in existing options and in options to be granted in the future. Following the amendment, an option holder, at their request, may receive either (a) common shares upon payment of the exercise price or (b) a direct cash payment for surrendered vested options for cancellation equal to the difference between the closing share price on the day preceding the exercise and the exercise price. The reasons for implementing the cash payment election are that the revised plan:

- Does not change the basic objective of the plan to provide incentive to employees to create value for shareholders and helps make the Company's compensation plans more competitive;

- Should substantially reduce the dilution arising from the exercise of vested stock options and the dilution implied by unvested stock options or future grants of options;

- Makes the program more transparent, as the Company will recognize a liability and compensation expense for all stock options issued and outstanding;

- Makes the program income tax efficient as all cash payments made to employees will become tax deductible for the Company; and,

- Creates certain administrative advantages for option holders while not materially affecting their tax liability.

Also in June 2003, the Company announced a small shareholders selling program, which allows registered and beneficial shareholders who own in aggregate 99 or fewer common shares to sell their shares without incurring any brokerage commission. The program ends on September 2, 2003. Interest parties should contact Georgeson Shareholders Communications Canada, Inc. for further details at 1-866-869-7468.

CORPORATE REVIEW

Canadian Natural also reports that Mr. Allan Markin, Chairman of the Company, is on a short-term leave of absence from his day to day company activities due to domestic issues. It is expected that Mr. Markin will resume his day to day activities in his role as Chairman no later than the end of September 2003. During this time, other members of Canadian Natural's management committee will assume Mr. Markin's Company duties.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations of Canadian Natural Resources Limited ("Canadian Natural" or the "Company"), should be read in conjunction with the unaudited interim consolidated financial statements for the three months and six months ended June 30, 2003 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2002.

All dollar amounts, except per common share data, are referenced in millions of Canadian dollars, except where noted otherwise. The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil to estimate relative energy content. Production volumes are the Company's interest before royalties, and realized prices include the effect of hedging gains and losses, except where noted otherwise.

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

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Revenue	**$ 1,413**	$ 1,628	$ 863	**$ 3,041**	$ 1,580
Cash flow from operations attributable to common shareholders[1]	**$ 762**	$ 906	$ 475	**$ 1,668**	$ 834
Per common share – basic	**$ 5.68**	$ 6.76	$ 3.86	**$ 12.43**	$ 6.82
– diluted	**$ 5.57**	$ 6.53	$ 3.70	**$ 12.18**	$ 6.57
Net earnings attributable to common shareholders[2]	**$ 525**	$ 428	$ 145	**$ 953**	$ 244
Per common share – basic	**$ 3.91**	$ 3.19	$ 1.18	**$ 7.11**	$ 2.00
– diluted	**$ 3.78**	$ 3.03	$ 1.09	**$ 6.86**	$ 1.89
Capital expenditures, net of dispositions	**$ 410**	$ 813	$ 305	**$ 1,223**	$ 764

(1) *Cash flow from operations attributable to common shareholders is a non-GAAP term that represents net earnings attributable to common shareholders adjusted for non-cash items. The Company evaluates its performance and that of its business segments based on net earnings and cash flow from operations. The Company considers cash flow a key measure as it demonstrates the Company's ability and the ability of its business segments to generate the cash flow necessary to fund future growth through capital investment and to repay debt.*

($ millions)	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Net earnings attributable to common shareholders	**$ 525**	$ 428	$ 145	**$ 953**	$ 244
Non-cash items:					
Future tax on dividend on preferred securities	**(1)**	(1)	(1)	**(2)**	(2)
Revaluation of preferred securities (net of tax)	**(7)**	(7)	(6)	**(14)**	(6)
Stock-based compensation	**105**	-	-	**105**	-
Depletion, depreciation and amortization	**384**	375	291	**759**	525
Unrealized foreign exchange gain	**(109)**	(119)	(64)	**(228)**	(76)
Deferred petroleum revenue tax	**4**	3	2	**7**	3
Future income tax	**(139)**	227	108	**88**	146
Cash flow from operations attributable to common shareholders	**$ 762**	$ 906	$ 475	**$ 1,668**	$ 834

(2) *After dividend and revaluation of preferred securities.*

Canadian Natural achieved record levels of net earnings for the three months ended June 30, 2003. Net earnings increased to $525 million, up 262% from the prior year and up 23% from the prior quarter. Cash flow was $762 million, up 60% from the prior year but down 16% from the prior quarter. The increase in cash flow in the second quarter of 2003, compared to the second quarter of 2002, was a result of higher product prices and higher production volumes. The increase in production volumes was primarily associated with the consolidation of the Company's interests in the North Sea, an active capital expenditure program and the acquisition of Rio Alto Exploration Ltd. ("Rio Alto") on July 1, 2002. Cash flow decreased from the prior quarter due to lower product prices. Net earnings increased over the comparable periods due to the reduction in the Canadian federal and Alberta provincial corporate income tax rates and the strengthening Canadian dollar, resulting in an unrealized foreign exchange gain on the Company's US dollar denominated debt. The increase in net earnings in the second quarter was partially offset by the recognition of a stock-based compensation expense associated with the Company's Stock Option Plan.

ANALYSIS OF QUARTERLY CHANGES IN REVENUE ($ millions)

	Crude oil and NGLs	Natural gas	Midstream	Total
June 30, 2002	$ 489	$ 361	$ 13	$ 863
Price variance	117	(72)	-	45
Volume variance	143	122	-	265
Other variance	-	-	-	-
September 30, 2002	749	411	13	1,173
Price variance	(57)	235	-	178
Volume variance	(5)	(18)	-	(23)
Other variance	-	-	2	2
December 31, 2002	687	628	15	1,330
Price variance	83	267	-	350
Volume variance	(15)	(40)	-	(55)
Other variance	-	-	3	3
March 31, 2003	755	855	18	1,628
Price variance	**(110)**	**(136)**	**-**	**(246)**
Volume variance	**16**	**19**	**-**	**35**
Other variance	**-**	**-**	**(4)**	**(4)**
June 30, 2003	$ **661**	$ **738**	$ **14**	$ **1,413**

OPERATING HIGHLIGHTS

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Crude oil and NGLs ($/bbl, except daily production)					
Daily production (bbls/d)	**240,607**	237,560	189,386	**239,092**	188,915
Sales price	**$ 30.27**	$ 35.26	$ 28.27	**$ 32.73**	$ 26.40
Royalties	**2.78**	3.56	3.02	**3.17**	2.65
Production expense	**10.80**	10.79	7.95	**10.79**	7.88
Netback	**$ 16.69**	$ 20.91	$ 17.30	**$ 18.77**	$ 15.87
Natural gas ($/mcf, except daily production)					
Daily production (mmcf/d)	**1,325**	1,310	1,078	**1,318**	1,066
Sales price	**$ 6.12**	$ 7.25	$ 3.68	**$ 6.67**	$ 3.38
Royalties	**1.35**	1.78	0.77	**1.56**	0.66
Production expense	**0.59**	0.57	0.57	**0.58**	0.58
Netback	**$ 4.18**	$ 4.90	$ 2.34	**$ 4.53**	$ 2.14
Barrels of oil equivalent ($/boe, except daily production)					
Daily production (boe/d)	**461,455**	455,952	369,022	**458,719**	366,520
Sales price	**$ 33.32**	$ 39.24	$ 25.29	**$ 36.25**	$ 23.46
Royalties	**5.32**	6.96	3.79	**6.13**	3.29
Production expense	**7.34**	7.27	5.76	**7.31**	5.75
Netback	**$ 20.66**	$ 25.01	$ 15.74	**$ 22.81**	$ 14.42

BUSINESS ENVIRONMENT

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
WTI benchmark price (US $/bbl)	**$ 28.90**	$ 33.80	$ 26.26	**$ 31.34**	$ 23.98
Differential to LLB blend (US $/bbl)	**$ 7.18**	$ 8.10	$ 6.04	**$ 7.64**	$ 5.89
Condensate benchmark price (US $/bbl)	**$ 29.88**	$ 33.30	$ 26.36	**$ 32.08**	$ 23.61
NYMEX benchmark price (US $/mmbtu)	**$ 5.48**	$ 6.64	$ 3.37	**$ 6.06**	$ 2.89
AECO benchmark price (Cdn $/mmbtu)	**$ 6.99**	$ 7.95	$ 4.43	**$ 7.47**	$ 3.89
US/Canadian dollar exchange rate (US $)	**0.72**	0.66	0.64	**0.69**	0.64

In the second quarter of 2003, world oil prices decreased but continued to remain strong due to continued uncertainty regarding North American oil supply. West Texas Intermediate (“WTI”) averaged US $28.90 per bbl in the second quarter of 2003, down 14% compared to US $33.80 per bbl in the prior quarter, and up 10% from US $26.26 per bbl compared to the second quarter of 2002.

PRODUCT PRICES

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Crude oil and NGLs ($/bbl)					
North America	**$ 27.64**	$ 30.20	$ 26.27	**$ 28.90**	$ 24.27
North Sea	**$ 37.83**	$ 50.27	$ 39.36	**$ 44.08**	$ 36.31
Offshore West Africa	**$ 34.34**	$ 37.86	$ 33.92	**$ 35.88**	$ 35.71
Company average	**$ 30.27**	$ 35.26	$ 28.27	**$ 32.73**	$ 26.40
Natural gas ($/mcf)					
North America	**$ 6.25**	$ 7.36	$ 3.72	**$ 6.80**	$ 3.39
North Sea	**$ 2.21**	$ 4.03	$ 1.80	**$ 3.12**	$ 2.92
Offshore West Africa	**$ 5.09**	$ 3.80	$ -	**$ 4.61**	$ -
Company average	**$ 6.12**	$ 7.25	$ 3.68	**$ 6.67**	$ 3.38
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**47.3%**	46.9%	57.5%	**47.1%**	58.1%
Natural gas	**52.7%**	53.1%	42.5%	**52.9%**	41.9%

Realized crude oil prices for all segments for the three months ended June 30, 2003 decreased from the prior quarter due to a decrease in the world oil price. In the second quarter of 2003, the heavy oil differential averaged US $7.18 per bbl, up 19% from US $6.04 per bbl in the second quarter of 2002 but down 11% from US $8.10 per bbl in the first quarter of 2003. As a result of the use of financial instruments, the realized price from the sale of crude oil was reduced by $0.39 per bbl in the quarter ended June 30, 2003 ($4.11 per bbl and $1.85 per bbl reduction, respectively, in the quarters ended March 31, 2003 and June 30, 2002). The realized crude oil prices for the six months ended June 30, 2003 increased from the comparable period in 2002 due to political unrest in the Middle East and concerns regarding world oil supply.

The Company average natural gas price increased from the comparable periods in 2002 and decreased 16% from the prior quarter due to fluctuations in seasonal demand and concerns over supply and storage levels. North American natural gas prices have remained strong since winter due to concerns over the industry's ability to replenish natural gas storage levels. AECO and NYMEX prices averaged $6.99 and US $5.48 per mmbtu, respectively, during the quarter ended June 30, 2003 compared to $7.95 and US $6.64 per mmbtu during the previous quarter and $4.43 and US $3.37 per mmbtu in the second quarter of 2002. Financial instruments entered into by the Company on its natural gas portfolio resulted in a reduction to realized prices. The price realized from the sale of its natural gas was decreased by $0.13 per mcf in the second quarter of 2003 ($0.50 per mcf and $0.09 per mcf reduction, respectively, in the quarters ended March 31, 2003 and June 30, 2002).

A comparison of the price received for the Company's North American production is as follows:

	Q2 2003	Q1 2003	Q2 2002
Canadian Natural's Wellhead Price[1]			
Light oil and NGLs (Cdn $/bbl)	**$ 35.54**	$ 38.52	$ **31.90**
Pelican Lake oil (Cdn $/bbl)	**$ 25.66**	$ 27.52	$ **25.05**
Primary heavy oil (Cdn $/bbl)	**$ 24.76**	$ 27.41	$ **24.54**
Thermal heavy oil (Cdn $/bbl)	**$ 24.22**	$ 25.44	$ **23.73**
Natural gas (Cdn $/mcf)	**$ 6.25**	$ 7.36	$ **3.72**

[1] *Including financial instruments.*

DAILY PRODUCTION

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Crude oil and NGLs (bbls/d)					
North America	**175,232**	173,045	158,196	**174,144**	155,248
North Sea	**55,781**	56,963	25,685	**56,369**	28,283
Offshore West Africa	**9,594**	7,552	5,505	**8,579**	5,384
Total	**240,607**	237,560	189,386	**239,092**	188,915
Natural gas (mmcf/d)					
North America	**1,278**	1,265	1,058	**1,272**	1,042
North Sea	**40**	41	20	**41**	24
Offshore West Africa	**7**	4	-	**5**	-
Total	**1,325**	1,310	1,078	**1,318**	1,066
Product mix					
Light crude oil and NGLs	**24.3%**	24.7%	19.0%	**24.5%**	19.4%
Pelican Lake crude oil	**5.6%**	5.5%	8.3%	**5.6%**	7.8%
Primary heavy crude oil	**13.8%**	13.2%	13.9%	**13.5%**	13.6%
Thermal heavy crude oil	**8.4%**	8.7%	10.1%	**8.5%**	10.7%
Natural gas	**47.9%**	47.9%	48.7%	**47.9%**	48.5%

Crude oil and NGLs production for the three and six months ended June 30, 2003 increased 27% or 51,221 bbls/d and 50,177 bbls/d respectively from the comparable periods in 2002. Crude oil and NGLs production for the second quarter of 2003 was in line with the Company's guidance of 230,000 to 251,000 bbls/d previously provided.

Crude oil and NGLs production in North America for the three and six months ended June 30, 2003 increased 11% or 17,036 bbls/d and 12% or 18,896 bbls/d respectively from the comparable periods in 2002. The increase was due to additional heavy oil drilling activity, property acquisitions in the Company's core operating regions in

North America, and the acquisition of Rio Alto. North America crude oil production increased 1% or 2,187 bbls/d over the prior quarter due to increased heavy oil drilling, which saw the drilling of 145 oil wells in North Alberta.

Crude oil production from the North Sea for the three and six months ended June 30, 2003 increased 117% or 30,096 bbls/d and 99% or 28,086 bbls/d respectively from the comparable periods in 2002. The increase was a result of drilling activities and the consolidation of the Company's working interests in the North Sea during the past year. Crude oil production decreased 2% or 1,182 bbls/d from the previous quarter due to planned extensive platform turnarounds in the second quarter of 2003. The production declines due to the turnarounds were partially offset by production from new in-fill drilling in the Ninian, Murchison and Columba fields and the re-entry into a number of producing wells to access behind pipe reserves.

Offshore West Africa crude oil production for the three months ended June 30, 2003 increased 74% or 4,089 bbls/d from the comparable period in 2002 and 27% or 2,042 bbls/d from the prior quarter due to the perforation of the upper zone of the East Espoir structure in the second quarter of 2003.

Natural gas continues to represent the Company's largest product and increased 23% from the comparable period in 2002 to average 1,325 mmcf/d for the three-month period ended June 30, 2003. Natural gas production for the six-month period ended June 30, 2003 increased 24% or 252 mmcf/d from the comparable period in 2002. The increase in natural gas production was due to the acquisition of Rio Alto on July 1, 2002 and ongoing drilling activities. Natural gas production increased 1% or 15 mmcf/d from the prior quarter reflecting the Company's winter 2003 natural gas drilling program. Production from the Ladyfern field in Northeast British Columbia continues to decline, averaging 62 mmcf/d during the second quarter of 2003, down from 76 mmcf/d in the first quarter of 2003 and 201 mmcf/d in the second quarter of 2002 as well pressures continue to decline.

Natural gas production in the North Sea increased from the comparable periods in the prior year due to the increased working interests acquired in the Banff field as a result of a property swap in 2002.

Natural gas production in Offshore West Africa increased over the comparable periods in 2002 due to the natural gas pipeline commencing operation in the third quarter of 2002. Natural gas production increased in the second quarter of 2003 due to the perforation of the upper zones of the East Espoir structure.

The Company expects 2003 production levels to average 1,280 to 1,330 mmcf/d of natural gas and 240,000 to 260,000 bbls/d of crude oil and NGLs, unchanged from previous expectations. Third quarter 2003 production guidance is 1,278 to 1,302 mmcf/d of natural gas and 242,000 to 256,000 bbls/d of crude oil and NGLs. North America natural gas production is anticipated to decline in the third quarter as normal production declines are expected to exceed production increases from the Company's shallow gas drilling program. In addition, the Alberta Energy and Utilities Board's recent decision to shut in certain natural gas production in the Athabasca Wabiskaw-McMurray oilsands area, in order to protect the future production of bitumen reserves, will have a minor impact on the Company's production. As a result of this decision, the Company expects to shut in approximately 15 to 20 mmcf/d of natural gas production on September 1, 2003. Dependent upon appeals by the Company, a further 5 to 10 mmcf/d of natural gas production may be required to be shut in.

ROYALTIES

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Crude oil and NGLs ($/bbl)					
North America	**$ 3.83**	$ 4.80	$ 3.29	**$ 4.31**	$ 2.88
North Sea	**$ (0.19)**	$ 0.11	$ 1.76	**$ (0.04)**	$ 1.64
Offshore West Africa	**$ 0.99**	$ 1.20	$ 1.11	**$ 1.08**	$ 1.37
Company average	**$ 2.78**	$ 3.56	$ 3.02	**$ 3.17**	$ 2.65
Natural gas ($/mcf)					
North America	**$ 1.40**	$ 1.84	$ 0.79	**$ 1.61**	$ 0.67
Offshore West Africa	**$ 0.15**	$ 0.11	$ -	**$ 0.14**	$ -
Company average	**$ 1.35**	$ 1.78	$ 0.77	**$ 1.56**	$ 0.66
Company average ($/boe)	**$ 5.32**	$ 6.96	$ 3.79	**$ 6.13**	$ 3.29
Percentage of revenue (excluding financial instruments)					
Crude oil and NGLs	**9.1%**	9.0%	10.0%	**9.1%**	9.6%
Natural gas	**21.6%**	22.9%	20.4%	**22.3%**	19.6%

North America crude oil and NGLs royalties increased on a per barrel basis over the comparable periods in the prior year as a result of higher oil prices and certain heavy oil projects reaching payout in 2002 and becoming subject to higher government royalties. North America crude oil and NGLs royalties decreased from the prior quarter due to the decrease in oil prices. North Sea crude oil royalties decreased from the comparable periods in the prior year as a result of the elimination of government royalties in the North Sea effective January 1, 2003. In the second quarter of 2003, the Company received a refund of royalties previously provided for on the Ninian field.

Natural gas royalty fluctuations as a percentage of revenue from both the prior quarter and the comparable prior year periods are a result of the strong correlation of royalties to natural gas prices.

PRODUCTION EXPENSE

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Crude oil and NGLs ($/bbl)					
North America	**$ 9.80**	$ 9.09	$ 6.52	**$ 9.45**	$ 6.74
North Sea	**$ 14.17**	$ 15.50	$ 15.72	**$ 14.84**	$ 12.66
Offshore West Africa	**$ 9.32**	$ 14.03	$ 12.76	**$ 11.38**	$ 15.61
Company average	**$ 10.80**	$ 10.79	$ 7.95	**$ 10.79**	$ 7.88
Natural gas ($/mcf)					
North America	**$ 0.56**	$ 0.55	$ 0.55	**$ 0.56**	$ 0.56
North Sea	**$ 1.45**	$ 1.09	$ 1.90	**$ 1.27**	$ 1.57
Offshore West Africa	**$ 1.45**	$ 2.37	$ -	**$ 1.79**	$ -
Company average	**$ 0.59**	$ 0.57	$ 0.57	**$ 0.58**	$ 0.58
Company average ($/boe)	**$ 7.34**	$ 7.27	$ 5.76	**$ 7.31**	$ 5.75

The increase in North America crude oil and NGLs production expense over the comparable three-month and six-month periods is primarily attributable to the increase in natural gas fuel costs. Natural gas is used to produce the steam to heat the Company's thermal oil formations in the Primrose area of Alberta. While the cost of natural gas used to generate steam decreased in the second quarter, this decrease was offset by higher steam/oil ratios associated with the high steam portion of the steam cycle. Crude oil and NGLs operating costs also increased due to higher start-up costs such as sand handling associated with new heavy oil wells drilled, and an active heavy oil recompletion program in the second quarter of 2003. The second quarter costs were also impacted by higher repairs and maintenance costs incurred with regard to recent acquisitions and costs associated with Pelican Lake, which have increased from historical levels due to the conversion and implementation of the waterflood pilots.

North Sea crude oil production expense for the three months ended June 30, 2003 decreased on a per barrel basis from both the prior quarter and the comparable period in 2002 due to the timing of maintenance work. North Sea crude oil production expense for the six months ended June 30, 2003 increased from the prior year due to the shut down of the Ninian South Platform during portions of the first and second quarter. Due to two unscheduled outages on the Ninian South Platform experienced in the first quarter, the Company accelerated and commenced the planned turnaround in the first quarter. The Ninian South Platform was shut in until late April in order to proactively replace critical pipework to significantly increase the reliability and integrity of the platform. North Sea crude oil and liquids production expense was high in the second quarter of 2002 due to a combination of costs associated with the natural gas pipeline blockage and lower production.

Offshore West Africa crude oil production costs are largely fixed in nature and therefore decreased on a per barrel basis from the comparable periods due to increased production from the Espoir field.

North America natural gas production expense for the three and six months ended June 30, 2003 was consistent with the prior quarters. North Sea natural gas production costs decreased from comparable periods in the prior year due to costs associated with the natural gas pipeline blockage that occurred in 2002. Offshore West Africa natural gas costs increased from the comparable periods in the prior year due to gas production commencing in the third quarter of 2002.

MIDSTREAM ($ millions)

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Revenue	**$ 14**	$ 18	$ 14	**$ 32**	$ 24
Operating costs	**3**	5	4	**8**	7
Operating cash flow	**11**	13	10	**24**	17
Depreciation	**2**	2	2	**4**	4
Segment earnings before taxes	**$ 9**	$ 11	$ 8	**$ 20**	$ 13

The Company's midstream assets consist of three crude oil pipeline systems and an 84-megawatt cogeneration plant at Primrose, where the Company has a 50% working interest. Approximately 82% of the Company's heavy oil production was transported to the international mainline liquid pipelines via the Company's 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 transport its own production volumes at reduced costs compared to other transportation alternatives as well as earn third party revenue. This transportation control enhances the Company's ability to control the full range of costs associated with the development and marketing of its heavy oil.

Revenue from the midstream assets increased for the six-month period ended June 30, 2003 from the comparable period in 2002 due to higher electricity prices received, substantially all related to the first quarter of 2003, and increased revenue generated by the ECHO pipeline. Revenue decreased for the three months ended June 30, 2003 from the prior quarter due to lower electricity prices. Revenue from the Company's midstream assets is expected to increase later in 2003 with the expansion of the ECHO pipeline capacity to 72 mbbls/d from 58 mbbls/d.

DEPLETION, DEPRECIATION AND AMORTIZATION(1)

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Expense ($ millions)	**$ 382**	$ 373	$ 289	**$ 755**	$ 521
$/boe	**$ 9.09**	$ 9.09	$ 8.61	**$ 9.09**	$ 7.86

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

Depletion, depreciation and amortization ("DD&A") for the three and six months ended June 30, 2003 increased in total and per boe from the comparable periods in 2002. The increase was due to higher finding and development costs associated with natural gas exploration in North America, the allocation of the acquisition costs associated with Rio Alto and future abandonment costs associated with the acquisition of additional interests in the North Sea.

ADMINISTRATION EXPENSE

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Net expense ($ millions)	**$ 23**	$ 18	$ 12	**$ 41**	$ 26
$/boe	**$ 0.56**	$ 0.44	$ 0.37	**$ 0.50**	$ 0.39

Administration expense for the three and six months ended June 30, 2003 increased in total and on a boe basis due to higher staffing levels associated with the growth in production and the expanding asset base.

Administration expense in the second quarter increased in total and on a boe basis due to lower overhead recoveries resulting from reduced drilling and construction activities.

STOCK-BASED COMPENSATION

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Expense ($ millions)	**$ 105**	$ -	$ -	**$ 105**	$ -
$/boe	**$ 2.49**	$ -	$ -	**$ 1.26**	$ -

In June 2003, the Board of Directors approved an amendment to the Company's Stock Option Plan (the "Option Plan") that provides current employees, officers and directors (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options exercised. The amendment to the Option Plan balances the need for a long-term compensation program to retain employees and the concerns of shareholders regarding dilution caused by stock options. Transparency of the cost of the Option Plan is increased since changes in the intrinsic value of outstanding stock options are expensed. The amendment also creates an income tax advantage for the Company since cash payments made for options exercised will be deductible for income tax purposes. 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.

As a result of the amendment to the Option Plan, the Company has recorded a liability of $103 million for expected cash settlements based on the intrinsic value of the outstanding stock options (the difference between the exercise price of the stock options and the market price of Canadian Natural's common shares). The compensation expense for the quarter is $105 million ($72 million after tax). The liability will be revalued quarterly to reflect changes in the market price of the Company's common shares and the net change will be recognized in net earnings for the quarter.

INTEREST EXPENSE

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Net expense ($ millions)	**$ 41**	$ 48	$ 29	**$ 89**	$ 57
$/boe	**$ 0.98**	$ 1.16	$ 0.85	**$ 1.07**	$ 0.86
Average effective interest rate	**4.9%**	4.9%	4.4%	**4.9%**	4.2%

Interest expense for the three and six months ended June 30, 2003 increased from the comparable period in 2002 due to higher debt levels associated with the acquisition of Rio Alto on July 1, 2002. The increase in interest expense was also affected by the increase in the Company's effective interest rate resulting from increases in the Canadian prime lending rate and a greater proportion of higher fixed rate debt. Interest expense decreased from the previous quarter due to lower debt levels as the Company used excess cash flow generated to repay $201 million of long-term debt. In addition, the strengthening Canadian dollar reduced the Canadian equivalent interest expense on the Company's US dollar denominated debt.

FOREIGN EXCHANGE ($ millions)

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Realized foreign exchange loss	**$ 10**	$ 1	$ 1	**$ 11**	$ 3
Unrealized foreign exchange gain	**(109)**	(119)	(64)	**(228)**	(76)
Total	**$ (99)**	$ (118)	$ (63)	**$ (217)**	$ (73)

The Canadian dollar continued to strengthen against the US dollar in the second quarter of 2003. The Canadian dollar increased to US $0.74 at the end of the second quarter compared to US $0.68 at the end of the first quarter of 2003 and to US $0.66 at June 30, 2002, resulting in an unrealized foreign exchange gain on the Company's US dollar denominated debt.

The Company's realized product prices are sensitive to currency exchange rates. The recent increases in the value of the Canadian dollar in relation to the US dollar have had a negative impact on the Company's commodity price realizations (See Sensitivity Analysis).

In order to mitigate a portion of the volatility associated with the Canadian dollar, the Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets. For the three and six months ended June 30, 2003, foreign exchange gains of $71 million and $133 million (June 30, 2002 - nil) were included in the foreign currency translation adjustment respectively.

TAXES ($ millions, except income tax rates)

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Taxes other than income tax					
Current	**$ 20**	$ 25	$ 11	**$ 45**	$ 25
Deferred	**4**	3	2	**7**	3
Total	**$ 24**	$ 28	$ 13	**$ 52**	$ 28
Current income tax					
North Sea	**$ 1**	$ 15	$ 2	**$ 16**	$ 13
Offshore West Africa	**2**	2	1	**4**	2
North America – Current income tax	**12**	16	-	**28**	-
North America – Large corporations tax	**4**	6	5	**10**	9
Total	**$ 19**	$ 39	$ 8	**$ 58**	$ 24
Future income tax	**$ (139)**	$ 227	$ 108	**$ 88**	$ 146
Effective income tax rate	**(30.0%)**	38.6%	45.1%	**13.4%**	41.3%

Taxes other than income tax consists of current and deferred petroleum revenue tax ("PRT"), other international taxes and provincial capital taxes. PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income, after certain deductions including abandonment expenditures. Taxes other than income taxes increased from the comparable periods in 2002 as a result of higher oil prices and increased production levels. The decrease in taxes other than income tax from the first quarter of 2003 is a result of the decrease in world oil prices.

North Sea current income tax in the first half of 2003 increased from the previous year due to the introduction of the supplementary charge of 10% on profits from UK North Sea crude oil and natural gas production. The North Sea supplementary charge, which took effect April 17, 2002, is in addition to the corporate tax rate of 30% and excludes any deduction for financing costs. Current income tax in the second quarter 2003 decreased from the first quarter due to lower operating income and the impact of the increase in the first year allowance rate for plant and machinery expenditures to 100% from the previous rate of 25%, also effective April 17, 2002.

Taxable income from the conventional crude oil and natural gas business in Canada is generated by partnerships and the related income taxes will be payable in the following year. Current income taxes have been provided on the basis of the corporate structure and available income tax deductions. No current income tax provision was required for North America in 2002.

In June 2003, the Canadian Federal Government introduced legislation to eliminate the federal Large Corporations Tax ("LCT") over a five-year period starting January 1, 2004. The LCT is currently levied at a rate of 0.225% of the Company's taxable capital employed in Canada. The Federal Government also introduced legislation to reduce the general corporate income tax rate on income from resource activities from 28% to 21% over a five-year period starting January 1, 2003, bringing the resource industry in line with the general corporate income tax rate. As part of the corporate income tax rate reduction, the legislation also plans for the elimination of the existing 25% resource allowance and the introduction of a deduction for actual provincial and other crown royalties paid. As a result of these changes, which are considered to be substantively enacted for Canadian GAAP purposes, the future income tax liability in North America was decreased by $216 million. In addition, the North America future tax liability was reduced by $31 million as a result of a reduction in the Alberta corporate income tax rate from 13% to 12.5%.

As a result of the above changes, there was a recovery of future income tax expense in the second quarter of 2003. A summary of the changes are as follows:

FUTURE INCOME TAX EXPENSE ($ millions)

	June 30, 2003	
	Three Months Ended	**Six Months Ended**
Future income tax expense before the following:	**$ 141**	**$ 368**
Canadian Federal resource income taxation changes	**(216)**	**(216)**
Alberta corporate income tax rate reduction	**(31)**	**(31)**
Tax effect of stock-based compensation expense	**(33)**	**(33)**
Future income tax (recovery)	**$ (139)**	**$ 88**

CAPITAL EXPENDITURES ($ millions)

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 23**	$ 178	$ 33	**$ 201**	$ 68
Land acquisition and retention	**36**	21	19	**57**	47
Seismic evaluations	**21**	19	14	**40**	39
Well drilling, completion and equipping	**190**	396	136	**586**	343
Pipeline and production facilities	**107**	149	67	**256**	191
Total net reserve replacement expenditures	**377**	763	269	**1,140**	688
Horizon Oil Sands Project	**27**	41	17	**68**	39
Midstream	**1**	3	5	**4**	15
Abandonments	**3**	3	12	**6**	19
Head office	**2**	3	2	**5**	3
Total net capital expenditures	**$ 410**	$ 813	$ 305	**$ 1,223**	$ 764
North America	**$ 288**	$ 643	$ 205	**$ 931**	$ 595
North Sea	**43**	90	13	**133**	(19)
Offshore West Africa	**46**	30	51	**76**	112
Horizon Oil Sands Project	**27**	41	17	**68**	39
Midstream	**1**	3	5	**4**	15
Abandonments	**3**	3	12	**6**	19
Other	**2**	3	2	**5**	3
Total	**$ 410**	$ 813	$ 305	**$ 1,223**	$ 764

During the second quarter of 2003, the Company drilled 224 wells, including 5 stratigraphic test and service wells. The drilling in the second quarter included 55 net natural gas wells and 157 net oil wells. Year to date, the Company has drilled a total of 299 net natural gas wells and 273 net oil wells, a 143% and a 41% increase respectively over the comparable period in 2002. The North American natural gas program included the start of the Company summer shallow gas program with the drilling of 32 wells in South Alberta. It is anticipated that an additional 100 shallow and 70 conventional and deep natural gas wells will be drilled in the third quarter of 2003. The Company's North American oil drilling program in the second quarter concentrated on North Alberta with the drilling of 126 net heavy oil wells as well as 13 net wells in Pelican Lake. In the third quarter, the Company expects to drill approximately 110 heavy oil wells. Capital expenditures also include the expansion of the Company's Primrose properties with the drilling of six thermal oil wells in the second quarter. An additional 18 wells will be drilled in the Primrose field during the last half of 2003, with steaming of these wells expected to commence late in the year. First production from these wells is not anticipated until the middle of 2004.

Capital expenditures also included work on the Horizon Oil Sands Project ("Horizon Project") where engineering work continues on the Design Basis Memorandum ("DBM"). The DBM is expected to be completed in August with Engineering and Design Specification to commence immediately thereafter. Work is also continuing on the access road, including the construction of three bridges. The Alberta Energy and Utilities Board and Alberta Environment, in co-operation with other Provincial and Federal regulatory agencies, have deemed the application for the Horizon Project as being complete. Regulatory hearings on the Horizon Project will commence on September 15, 2003.

North Sea capital expenditures included drilling three successful oil wells targeting reserves stranded against faults within the Ninian and Murchison fields.

Offshore West Africa capital expenditures included the continued development of the Espoir field located offshore Côte d'Ivoire with the perforation of the upper zone of the East Espoir structure during the second quarter of 2003. Development of the Baobab field continues with three major contracts being awarded early in the third quarter of 2003 for the drilling; supply of subsea Xmas trees, manifolds, flowlines, controls and associated equipment; and the supply and operation of a Floating Production, Storage and Offtake vessel. The drilling of the wells will commence in the fourth quarter of 2003 with oil production commencing in the first half of 2005. The second quarter also saw the successful drilling of the Acajou satellite pool. The well was production tested, and although the productive oil bearing sands encountered are thin, additional sand which holds significant potential on the northern portion of the structure was encountered. The Company also continued to reprocess seismic on Block 16 located offshore Angola to optimize the locations on two separate structures, Zenza and Omba. As a result of the seismic reprocessing and the results of nearby drilling completed on Block 32 by another operator, the Company will drill one of the two structures in the fourth quarter.

LIQUIDITY AND CAPITAL RESOURCES ($ millions, except ratios)

	June 30 2003	March 31 2003	December 31 2002	June 30 2002
Working capital deficit	**$ 459**	$ 318	$ 14	$ 129
Long-term debt	**2,904**	3,494	4,074	2,405
Total	**$ 3,363**	$ 3,812	$ 4,088	$ 2,534
Shareholders' equity				
Preferred securities	**$ 108**	$ 118	$ 126	$ 122
Share capital	**2,360**	2,327	2,304	1,756
Retained earnings	**3,285**	2,801	2,414	2,122
Foreign currency translation adjustment	**10**	16	24	30
Total	**$ 5,763**	$ 5,262	$ 4,868	$ 4,030
Debt to cash flow(1)(2)	**1.0x**	1.3x	1.8x	1.5x
Debt to book capitalization(2)	**35.0%**	40.1%	45.7%	37.5%
Debt to market capitalization(2)	**29.7%**	34.0%	39.1%	27.2%
After tax return on average common shareholders' equity(1)	**26.7%**	20.3%	13.8%	10.3%
After tax return on average capital employed(1)	**16.5%**	12.6%	8.9%	7.2%

(1) *Based on trailing 12-month activity.*
(2) *Includes current portion of long-term debt.*

The Company recognizes the need for a strong financial position in order to withstand volatile oil and natural gas commodity prices and the operational risks inherent in the oil and natural gas business environment. During the second quarter, long-term debt was reduced by $201 million through debt repayments and $211 million as a result of foreign exchange gains on the Company's US dollar denominated debt. In the first six months of 2003, $578 million of long-term debt was repaid. Long-term debt was also reduced by an additional $414 million as a result of foreign exchange gains. Higher than budgeted prices received for the Company's products during the first half of 2003 have resulted in increased cash flow to the Company in 2003 over the budget established in late 2002. The Company is continuing to monitor its expected cash flow surplus and at present intends to allocate a minimum of 50% of such amounts toward debt repayment. The remaining excess will be directed to the Company's authorized share buy-back program and additional expenditures on conventional oil and natural gas opportunities. These expenditures will only be incurred as excess cash flow is realized and will be subject to the same economic tests as regular budgeted expenditures. Should additional economic opportunities for share buy-back or capital activities not materialize to the extent allocated, such allocations of surplus cash flow would revert to debt repayment. To date an additional $40 million has been allocated to the North American natural gas capital program and an additional $40 million to the drilling of heavy oil wells.

During the quarter, the Company prepaid the US $50 million 6.5% senior unsecured notes due May 1, 2008 for US $56 million, which included an early prepayment premium as required under the Note Purchase Agreement.

On January 22, 2003, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 6,692,799 common shares or 5% of the outstanding common shares of the Company on the date of announcement during the 12-month period beginning January 24, 2003 and ending January 23, 2004. As of August 5, 2003, the Company had purchased 1,409,800 common shares for a total cost of $69 million (June 30, 2003 - 1,329,800 common shares for a total cost of $65 million).

On June 16, 2003, the Company announced a small shareholder selling program ("the program") that enables registered and beneficial shareholders who own in aggregate 99 or fewer common shares of the Company as of June 13, 2003 ("Eligible Shareholders") to sell their shares without incurring any brokerage commission. The sale of shares will be executed through the facilities of the Toronto Stock Exchange. The voluntary program ends on September 2, 2003 and is designed to assist Eligible Shareholders in selling their shares in a convenient and inexpensive manner.

COMMITMENTS

Development of the Baobab field continues with three major contracts being awarded early in the third quarter of 2003. These contracts include the deepwater drilling agreement that will see eight producing and three water injector wells drilled in a water depth of approximately 4,000 feet; supply of subsea Xmas trees, manifolds, flowlines, controls and associated equipment; and the supply and operation of a Floating Production, Storage and Offtake vessel. A fourth major contract for the supply of pipelines, risers and installation of all of the subsea equipment is still to be awarded.

SENSITIVITY ANALYSIS [1]

Annualized sensitivities to certain factors that would influence the Company's financial results are estimated as follows:

	Cash flow from operations[2] ($ millions)	Cash flow from operations[2] (per common share, basic)	Net earnings[2] ($ millions)	Net earnings[2] (per common share, basic)
Price changes				
Crude oil – WTI US $1.00/bbl[3]				
Excluding financial derivatives	$89	$0.66	$63	$0.47
Including financial derivatives	$81	$0.60	$57	$0.42
Natural gas – AECO Cdn $0.10/mcf[3]				
Excluding financial derivatives	$33	$0.24	$19	$0.14
Including financial derivatives	$31	$0.23	$18	$0.14
Volume changes				
Crude oil – 10,000 bbls/d	$50	$0.37	$16	$0.12
Natural gas – 10 mmcf/d	$16	$0.12	$6	$0.05
Foreign currency rate change				
$0.01 change in Cdn $ in relation to US $[3]				
Excluding financial derivatives	$62	$0.46	$23	$0.17
Including financial derivatives	$56	$0.41	$19	$0.14
Interest rate change - 1%	$11	$0.08	$11	$0.08

(1) *The sensitivities are calculated based on 2003 second quarter results.*
(2) *Attributable to common shareholders.*
(3) *For details of financial derivatives in place, see the interim consolidated financial statement note 10.*

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in the Management's Discussion and Analysis for Canadian Natural Resources Limited 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 or words of a similar nature. Actual future results may differ materially. Canadian Natural's annual report to shareholders and other documents filed with securities regulatory authorities describe the risks, uncertainties and other factors, such as changes in business plans and estimated amounts and timing of capital expenditures and changes in estimates of future production, that could influence actual results. 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. 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. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS ($/boe, except daily production)

	Three Months Ended			Six Months Ended	
	June 30 2003	March 31 2003	June 30 2002	**June 30 2003**	June 30 2002
Daily production (boe/d)	**461,455**	455,952	369,022	**458,719**	366,520
Sales price	**$ 33.32**	$ 39.24	$ 25.29	**$ 36.25**	$ 23.46
Royalties	**5.32**	6.96	3.79	**6.13**	3.29
Production expense	**7.34**	7.27	5.76	**7.31**	5.75
Netback	**20.66**	25.01	15.74	**22.81**	14.42
Midstream contribution	**(0.25)**	(0.32)	(0.30)	**(0.29)**	(0.26)
Administration	**0.56**	0.44	0.37	**0.50**	0.39
Interest	**0.98**	1.16	0.85	**1.07**	0.86
Foreign exchange loss	**0.23**	0.02	0.03	**0.13**	0.05
Taxes other than income tax (current)	**0.48**	0.63	0.35	**0.55**	0.38
Current income tax (North Sea)	**0.02**	0.37	0.07	**0.19**	0.20
Current income tax (Offshore West Africa)	**0.04**	0.05	0.03	**0.05**	0.03
Current income tax (North America)	**0.28**	0.39	-	**0.33**	-
Current income tax (Large corporations tax)	**0.12**	0.13	0.14	**0.13**	0.13
Cash flow	**$ 18.20**	$ 22.14	$ 14.20	**$ 20.15**	$ 12.64

SEGMENTED NETBACK	Six Months Ended June 30, 2003			
	North America	North Sea	Offshore West Africa	Total
Crude oil and NGLs ($/bbl, except daily production)				
Daily production (bbls/d)	174,144	56,369	8,579	239,092
Sales price	$ 28.90	$ 44.08	$ 35.88	$ 32.73
Royalties	4.31	(0.04)	1.08	3.17
Production expense	9.45	14.84	11.38	10.79
Netback	$ 15.14	$ 29.28	$ 23.42	$ 18.77
Natural gas ($/mcf, except daily production)				
Daily production (mmcf/d)	1,272	41	5	1,318
Sales price	$ 6.80	$ 3.12	$ 4.61	$ 6.67
Royalties	1.61	-	0.14	1.56
Production expense	0.56	1.27	1.79	0.58
Netback	$ 4.63	$ 1.85	$ 2.68	$ 4.53
Barrels of oil equivalent ($/boe, except daily production)				
Daily production (boe/d)	386,093	63,132	9,494	458,719
Sales price	$ 35.44	$ 41.37	$ 35.09	$ 36.25
Royalties	7.27	(0.04)	1.06	6.13
Production expense	6.10	14.07	11.32	7.31
Netback	$ 22.07	$ 27.34	$ 22.71	$ 22.81

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)	June 30 2003	December 31 2002
ASSETS		
Current assets		
Cash	$ 18	$ 30
Accounts receivable and other	834	745
	852	775
Property, plant and equipment (net)	12,777	12,500
Deferred charges	82	84
	$ 13,711	$ 13,359
LIABILITIES		
Current liabilities		
Accounts payable	$ 486	$ 337
Accrued liabilities	623	428
Current portion of long-term debt (note 3)	202	24
	1,311	789
Long-term debt (note 3)	2,904	4,074
Deferred credits (note 4)	437	440
Future income tax (note 5)	3,296	3,188
	7,948	8,491
SHAREHOLDERS' EQUITY		
Preferred securities	108	126
Share capital (note 6)	2,360	2,304
Retained earnings	3,285	2,414
Foreign currency translation adjustment (note 7)	10	24
	5,763	4,868
	$ 13,711	$ 13,359

Commitments (note 11)

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended **June 30 2003**	 June 30 2002	Six Months Ended **June 30 2003**	 June 30 2002
Revenue	**$ 1,413**	$ 863	**$ 3,041**	$ 1,580
Less: royalties	**(223)**	(127)	**(509)**	(218)
	1,190	736	**2,532**	1,362
Expenses				
Production	**312**	197	**615**	388
Depletion, depreciation and amortization	**384**	291	**759**	525
Administration	**23**	12	**41**	26
Stock-based compensation (note 6)	**105**	-	**105**	-
Interest	**41**	29	**89**	57
Foreign exchange gain	**(99)**	(63)	**(217)**	(73)
	766	466	**1,392**	923
Earnings before taxes	**424**	270	**1,140**	439
Taxes other than income tax	**24**	13	**52**	28
Current income tax (note 5)	**19**	8	**58**	24
Future income tax (recovery) (note 5)	**(139)**	108	**88**	146
Net earnings	**520**	141	**942**	241
Dividend on preferred securities (net of tax)	**(2)**	(2)	**(3)**	(3)
Revaluation of preferred securities (net of tax)	**7**	6	**14**	6
Net earnings attributable to common shareholders	**$ 525**	$ 145	**$ 953**	$ 244
Net earnings attributable to common shareholders per common share (note 8)				
Basic	**$ 3.91**	$ 1.18	**$ 7.11**	$ 2.00
Diluted	**$ 3.78**	$ 1.09	**$ 6.86**	$ 1.89

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Six Months Ended June 30 **2003**	 2002
Balance – beginning of period	**$ 2,414**	$ 1,908
Net earnings	**942**	241
Dividend on common shares (note 6)	**(40)**	(30)
Purchase of common shares (note 6)	**(42)**	-
Dividend on preferred securities (net of tax)	**(3)**	(3)
Revaluation of preferred securities (net of tax)	**14**	6
Balance – end of period	**$ 3,285**	$ 2,122

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended June 30 2003	Three Months Ended June 30 2002	Six Months Ended June 30 2003	Six Months Ended June 30 2002
Operating activities				
Net earnings	**$ 520**	$ 141	**$ 942**	$ 241
Non-cash items				
Depletion, depreciation and amortization	**384**	291	**759**	525
Deferred petroleum revenue tax	**4**	2	**7**	3
Stock-based compensation	**105**	-	**105**	-
Future income tax (recovery)	**(139)**	108	**88**	146
Unrealized foreign exchange gain	**(109)**	(64)	**(228)**	(76)
Cash flow provided from operations	**765**	478	**1,673**	839
Deferred charges	**(3)**	-	**2**	-
Net change in non-cash working capital	**(98)**	45	**(180)**	(13)
	664	523	**1,495**	826
Financing activities				
Repayment of bank credit facilities	**(129)**	(172)	**(501)**	(823)
Repayment of senior unsecured notes	**(71)**	-	**(71)**	-
Issue of US debt securities	**-**	-	**-**	642
Repayment of lease obligations	**(1)**	-	**(6)**	-
Issue of capital stock	**45**	17	**79**	59
Purchase of common shares	**(33)**	-	**(65)**	-
Dividend on common shares	**(20)**	(15)	**(37)**	(27)
Dividend on preferred securities	**(3)**	(3)	**(5)**	(5)
Net change in non-cash working capital	**(10)**	7	**(8)**	-
	(222)	(166)	**(614)**	(154)
Investing activities				
Expenditures on property, plant and equipment	**(421)**	(307)	**(1,241)**	(822)
Net proceeds on sale of property, plant and equipment	**11**	2	**18**	58
Net expenditures on property, plant and equipment	**(410)**	(305)	**(1,223)**	(764)
Net change in non-cash working capital	**(31)**	(87)	**330**	78
	(441)	(392)	**(893)**	(686)
Increase (decrease) in cash	**1**	(35)	**(12)**	(14)
Cash – beginning of period	**17**	36	**30**	15
Cash – end of period	**$ 18**	$ 1	**$ 18**	$ 1

Supplemental disclosure of cash flow information (note 9)

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, 2002, 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, 2002.

2. ACCOUNTING POLICY

As a result of modifications to its Stock Option Plan (note 6), in the second quarter 2003 the Company prospectively adopted the following accounting policy with respect to stock-based compensation.

Stock-based compensation

The Company accounts for its stock-based compensation using the intrinsic value method. A liability for expected cash settlements under the Company's Stock Option Plan (the "Option Plan") is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the net change is recognized in net earnings. Consideration paid by employees, officers or directors and the liability associated with the stock options is recorded as share capital when stock options are exercised for common shares under the Option Plan.

3. LONG-TERM DEBT

	June 30 2003	December 31 2002
Bank credit facilities		
Canadian dollar debt	**$ 145**	$ 728
US dollar debt (2003 – US $207 million, 2002 – US $150 million)	**281**	237
Medium-term notes	**250**	250
Senior unsecured notes (2003 – US $268 million, 2002 – US $318 million)	**388**	499
US dollar debt securities (2003 – US $1,500 million, 2002 – US $1,500 million)	**2,033**	2,369
Obligations under capital leases	**9**	15
	3,106	4,098
Less: current portion of long-term debt	**202**	24
	$ 2,904	$ 4,074

Bank credit facilities

At June 30, 2003, the Company had unsecured bank credit facilities of $1,775 million comprised of a $100 million operating demand facility and a revolving credit and term loan facility of $1,675 million. During the first quarter of 2003, the Company repaid and cancelled a $500 million acquisition term credit facility.

In addition to the outstanding debt, letters of credit aggregating $17 million have been issued.

Medium-term notes

In August 2003, the Company filed a short form shelf prospectus that allows for the issue of up to $1 billion of medium-term notes in Canada until September 2005. If issued, these securities will bear interest as determined at the date of issuance.

Senior unsecured notes

In May 2003, the Company prepaid the US $50 million 6.50% senior unsecured notes due May 1, 2008 for US $56 million, which includes an early prepayment premium as required under the Note Purchase Agreement.

US dollar debt securities

In May 2003, the Company filed a short form shelf prospectus that allows for the issue of up to US $2 billion of debt securities in the United States until June 2005. If issued, these securities will bear interest as determined at the date of issuance.

4. DEFERRED CREDITS

	June 30 2003	December 31 2002
Provision for future site restoration	**$ 433**	$ 440
Stock-based compensation	**4**	-
	$ 437	$ 440

5. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Six Months Ended	
	June 30 2003	June 30 2002	**June 30 2003**	June 30 2002
Current income tax expense				
Current income tax – North America	**$ 12**	$ -	**$ 28**	$ -
Large corporations tax – North America	**4**	5	**10**	9
Current income tax – North Sea	**1**	2	**16**	13
Current income tax – Offshore West Africa	**2**	1	**4**	2
	19	8	**58**	24
Future income tax (recovery)	**(139)**	108	**88**	146
Income taxes	**$ (120)**	$ 116	**$ 146**	$ 170

A significant portion of the Company's North American taxable income is generated by partnerships. Current income taxes are incurred on the partnerships' taxable income in the year following their inclusion in the Company's consolidated net earnings.

In May 2003, the Government of Alberta introduced legislation to reduce its corporate income tax rate by 0.5% effective April 1, 2003. In June 2003, the Canadian federal government introduced legislation to change the taxation of resource income. The legislation reduces the corporate income tax rate on resource income from 28% to 21% over five years beginning January 1, 2003. Over the same period, the deduction for resource allowance is phased out and a deduction of actual crown royalties paid is phased in. These changes are considered substantively enacted for the purposes of Canadian GAAP and accordingly, the Company's future income tax liability has been reduced by $31 million with respect to the Alberta corporate income tax rate reduction and by $216 million with respect to the Federal resource income tax rate changes. The effect of these reductions has been recognized in the future income tax expense (recovery) for the three- and six-month periods ended June 30, 2003.

6. SHARE CAPITAL

Issued

	Six Months Ended June 30, 2003		
Common shares	**Number of shares** (thousands)		**Amount**
Balance – beginning of period	**133,776**	**$**	**2,304**
Issued upon exercise of stock options	**2,387**		**79**
Purchase of shares under Normal Course Issuer Bid	**(1,330)**		**(23)**
Balance – end of period	**134,833**	**$**	**2,360**

Normal course issuer bid

On January 22, 2003, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 6,692,799 common shares or 5% of the outstanding common shares of the Company on the date of announcement during the 12-month period beginning January 24, 2003 and ending January 23, 2004. As at June 30, 2003, the Company had purchased 1,329,800 common shares for a total cost of $65 million. The excess cost over book value of the shares purchased was applied to retained earnings.

Subsequent to June 30, 2003, the Company has purchased an additional 80,000 common shares for a total cost of $4 million.

Dividend policy

On February 26, 2003, the Board of Directors set the regular quarterly dividend at $0.15 per common share (2002 - $0.125 per common share). The Company pays regular quarterly dividends in January, April, July, and October of each year.

Stock options

	Six Months Ended June 30, 2003		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**12,882**	**$**	**37.13**
Granted	**190**	**$**	**48.44**
Exercised for cash settlement	**(47)**	**$**	**33.19**
Exercised for common shares	**(2,387)**	**$**	**33.10**
Forfeited	**(344)**	**$**	**42.86**
Outstanding – end of period	**10,294**	**$**	**38.10**
Exercisable – end of period	**2,954**	**$**	**34.69**

Modification of Stock Option Plan

During June 2003, the Company approved an amendment to its Option Plan providing the stock option holder the right to elect to receive a cash payment equal to the difference between the exercise price of the stock option and the market price of the Company's common shares on the date of exercise, multiplied by the number of common shares covered by the stock options exercised, in lieu of receiving common shares.

The modification to the Option Plan was accounted for prospectively and for the six months ended June 30, 2003, the Company recorded compensation expense of $105 million. As at June 30, 2003, the total liability for expected cash settlements under the Option Plan is $103 million, of which $99 million is included as a current liability.

Prior to the amendment, the Company disclosed pro-forma measures of net earnings attributable to common shareholders and net earnings attributable to common shareholders per common share as if stock options had been recongnized as compensation expense estimated on the date of grant using the Black-Scholes option pricing model. As stock-based compensation is now reflected in the Statement of Earnings, the pro-forma disclosures are no longer required.

7. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

The foreign currency translation adjustment represents the unrealized gain (loss) on the Company's net investment in self-sustaining foreign operations. The Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, gains and losses on this debt are included in the foreign currency translation adjustment.

	Six Months Ended June 30, 2003
Balance – beginning of period	$ 24
Unrealized loss on translation of net investment	(122)
Hedge of net investment with US dollar denominated debt (net of tax)	108
Balance – end of period	$ 10

8. NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	June 30 2003	June 30 2002	**June 30 2003**	June 30 2002
Weighted average common shares outstanding (thousands)				
Basic	**134,205**	122,910	**134,121**	122,264
Effect of dilutive stock options	**996**	3,500	**1,030**	2,986
Assumed settlement of preferred securities with common shares	**2,098**	2,344	**2,170**	2,484
Diluted	**137,299**	128,754	**137,321**	127,734
Net earnings attributable to common shareholders	**$ 525**	$ 145	**$ 953**	$ 244
Dividend on preferred securities (net of tax)	**2**	2	**3**	3
Revaluation of preferred securities (net of tax)	**(7)**	(6)	**(14)**	(6)
Diluted net earnings attributable to common shareholders	**$ 520**	$ 141	**$ 942**	$ 241
Net earnings attributable to common shareholders per common share				
Basic	**$ 3.91**	$ 1.18	**$ 7.11**	$ 2.00
Diluted	**$ 3.78**	$ 1.09	**$ 6.86**	$ 1.89

9. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Three Months Ended		Six Months Ended	
	June 30 2003	June 30 2002	**June 30 2003**	June 30 2002
Interest paid	**$ 60**	$ 21	**$ 102**	$ 47
Taxes paid	**$ 8**	$ 35	**$ 1**	$ 64

10. FINANCIAL INSTRUMENTS

The Company uses certain derivative financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The Company has the following financial derivatives outstanding as at August 5, 2003:

	Remaining Term	Volume	Average Price	*Index*
Oil				
Brent differential swaps	Jul. 2003 – Dec. 2003	15,000 bbls/d	US $1.00	Dated Brent/WTI
	Jan. 2004 – Dec. 2004	17,000 bbls/d	US $1.16	Dated Brent/WTI
Oil price collars	Jul. 2003 – Sep. 2003	120,000 bbls/d	US $24.16 – US $29.52	WTI
	Oct. 2003 – Dec. 2003	100,000 bbls/d	US $25.20 – US $31.14	WTI
	Jan. 2004 – Mar. 2004	60,000 bbls/d	US $25.00 – US $30.10	WTI
	Apr. 2004 – Jun. 2004	30,000 bbls/d	US $24.00 – US $29.02	WTI

	Remaining Term	Volume	Average Price	*Index*
Natural gas				
NYMEX collar	Jul. 2003 – Oct. 2003	30,000 mmbtu/d	US $2.88 – US $6.12	NYMEX
Sumas fixed	Jul. 2003 – Oct. 2003	10,000 mmbtu/d	Cdn $2.85	Sumas
AECO collars	Jul. 2003 – Sep. 2003	40,000 GJ/d	Cdn $3.50 – Cdn $5.38	AECO
	Oct. 2003	40,000 GJ/d	Cdn $3.50 – Cdn $5.38	AECO

	Remaining Term	Amount ($ millions)	Average Exchange Rate (US $/Cdn $)
Foreign currency			
Currency collars	Jul. 2003 – Aug. 2004	US $25/month	1.51 – 1.59
	Jan. 2004 – Dec. 2004	US $3/month	1.45 – 1.54

	Remaining Term	Amount ($ millions)	Exchange Rate (US $/Cdn $)	**Interest Rate** (US $)	**Interest Rate** (Cdn $)
Currency swap	Jul. 2003 – Dec. 2005	US $125	1.55	7.69%	7.30%

	Remaining Term	Amount ($ millions)	Fixed Rate	Floating Rate
Interest rate				
Swaps – fixed to floating	Jul. 2003 – Jul. 2004	US $200	6.70%	LIBOR + 2.09%
	Jul. 2003 – Jul. 2006	US $200	6.70%	LIBOR + 1.58%
	Jul. 2003 – Jan. 2005	US $200	7.20%	LIBOR + 3.00%
	Jul. 2003 – Jan. 2007	US $200	7.20%	LIBOR + 2.23%
	Jul. 2003 – Oct. 2012	US $350	5.45%	LIBOR + 0.81%
Swaps – floating to fixed	Jul. 2003 – Mar. 2004	Cdn $100	5.08%	CDOR
	Jul. 2003 – Mar. 2007	Cdn $16	7.36%	CDOR

11. COMMITMENTS

Subsequent to June 30, 2003, the Company signed a lease for a Floating Production, Storage and Offtake ("FPSO") vessel for the Baobab Field, located offshore Côte d'Ivoire, West Africa. The total lease payment obligation over a 10-year period is US $500 million commencing in 2005.

12. SEGMENTED INFORMATION

	Three Months Ended		Six Months Ended	
	June 30 2003	June 30 2002	**June 30 2003**	June 30 2002
Revenue				
North America	**$ 1,166**	$ 737	**$ 2,476**	$ 1,323
North Sea	**200**	95	**473**	198
Offshore West Africa	**33**	17	**60**	35
Midstream	**14**	14	**32**	24
	$ 1,413	$ 863	**$ 3,041**	$ 1,580
Net Earnings				
North America	**$ 481**	$ 202	**$ 842**	$ 275
North Sea	**18**	(40)	**69**	(20)
Offshore West Africa	**13**	(26)	**17**	(22)
Midstream	**8**	5	**14**	8
	520	141	**942**	241
Dividend on preferred securities (net of tax)	**(2)**	(2)	**(3)**	(3)
Revaluation of preferred securities (net of tax)	**7**	6	**14**	6
Net Earnings Attributable to Common Shareholders	**$ 525**	$ 145	**$ 953**	$ 244
Additions to Property, Plant and Equipment				
North America	**$ 288**	$ 205	**$ 931**	$ 595
North Sea	**41**	10	**148**	(45)
Offshore West Africa	**46**	51	**76**	112
Horizon Oil Sands Project	**27**	17	**68**	39
Midstream	**1**	5	**4**	15
Abandonments	**3**	12	**6**	19
Other	**2**	2	**5**	3
	$ 408	$ 302	**$ 1,238**	$ 738

	Property, Plant and Equipment		Total Assets	
	June 30 2003	December 31 2002	**June 30 2003**	December 31 2002
Segmented Assets				
North America	**$ 10,599**	$ 10,252	**$ 11,324**	$ 10,917
North Sea	**1,079**	1,277	**1,241**	1,427
Offshore West Africa	**579**	518	**605**	549
Horizon Oil Sands Project	**297**	229	**297**	229
Midstream	**195**	196	**216**	209
Other	**28**	28	**28**	28
	$ 12,777	$ 12,500	**$ 13,711**	$ 13,359

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 July 24, 2001. These ratios are based on the Company's consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the 12-month period ended June 30, 2003:	
Interest coverage (times)	
Net earnings	9.7 (1)
Cash flow from operations attributable to common shareholders	17.5 (2)

(1) *Net earnings plus income taxes and interest expense; divided by interest expense.*

(2) *Cash flow from operations attributable to common shareholders plus current income taxes and interest expense; divided by interest expense.*

The interest coverage ratios have been calculated without including the annual carrying charges relating to the outstanding preferred securities of the Company. If the preferred securities were classified as long-term debt, these annual carrying charges would be included in interest. If these annual carrying charges had been included in the calculations, the net earnings coverage ratio for the 12-month period ended June 30, 2003, would be 9.3x and the cash flow coverage ratio for the 12-month period ended June 30, 2003 would be 16.6x.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time, on Wednesday, August 6, 2003. The North American conference call number is 1-800-682-5077 and the outside North America conference call number is 1-416-620-2401. Please call in about 10 minutes before the starting time in order to be patched into the call. Should you experience difficulty in connecting to the call, those in North America should please call 1-800-473-0602 and then press option 1. Those outside North America should please call 1-905-502-3723 and then press option 1.

Media are invited to participate in listen-only mode.

Replay: A taped rebroadcast will be available until August 13, 2003, inclusive. To access postview in North America, dial 1-800-558-5253 and enter the passcode 21155066. Those outside of North America dial 1-416-626-4100 and enter the passcode number 21155066.

2003 THIRD QUARTER RESULTS

2003 third quarter results are scheduled for release Wednesday, November 5, 2003. A conference call will be held on that day at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time.

For further information, please contact:

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