Canadian Natural

Q1

Three months ended
March 31, 2003

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD QUARTERLY RESULTS

In commenting on first quarter 2003 results, Canadian Natural's Chairman, Allan Markin, stated "For the third consecutive quarter, we have achieved record cash flow levels and this was a remarkable quarter for Canadian Natural in several other respects. From an operational perspective, we accomplished the most aggressive drilling program in our history with 749 total wells drilled and a 94% success rate. In Western Canada, we are on track with our plan to extract value from the natural gas prone Northwest Alberta core region. In the North Sea, we have delivered new reserves and are proving that significant upside can still be extracted from these mature reservoirs."

"From an economic perspective, we have generated record quarterly earnings and cash flows. Our quarter-end balance sheet continued to strengthen with debt to book capitalization of 40%, just nine months after the acquisition of Rio Alto, when the same ratio was approximately 48%. This ratio at the end of the first quarter was achieved even with the repurchase of 665,600 common shares under our share-buyback plan."

"We have also enhanced the overall governance of the organization with major changes to the composition of the Committees of the Board of Directors. Each of the Governance, Compensation and Audit Committees are now solely comprised of unrelated directors. This, coupled with the formalization of various management roles, has resulted in a continued strengthening of our effective system of governance."

"All of this results in the generation of significant shareholder value. During the quarter we clearly benefited from strong commodity prices, but we also wisely reinvested in a very efficient manner. We expect our disciplined development strategy to continue to provide robust returns, particularly when this proven and effective approach is coupled with our well balanced and strong asset base, which will provide years of significant, low-risk growth."

HIGHLIGHTS OF THE FIRST QUARTER

- Record net earnings of $428 million ($3.19 per common share) compared with $99 million ($0.81 per common share) for the first quarter of 2002 and $209 million ($1.56 per common share) in the previous quarter.

- Record cash flow of $906 million ($6.76 per common share) compared with $359 million ($2.95 per common share) in the first quarter of 2002 and $777 million ($5.81 per common share) in the previous quarter.

- Natural gas sales of 1,310 million cubic feet per day, representing 48% of equivalent production during the quarter.

- Crude oil and NGLs sales of 238 thousand barrels per day.

- Reduced long-term debt by $580 million during the quarter through repayments of $377 million and foreign exchange gains of $203 million from the strengthening of the Canadian dollar. This reduced debt to book capitalization to 40%, compared with 46% at year end 2002 and 48% immediately following the acquisition of Rio Alto Exploration Ltd. on July 1, 2002.

- Capital expenditures of $813 million, reflecting the high activity levels associated with winter drilling areas. During the quarter, Canadian Natural drilled a record 749 wells, including 244 natural gas wells.

- Extended its Normal Course Issuer Bid for a further 12-month period through the facilities of the Toronto Stock Exchange and the New York Stock Exchange for the purchase of up to 5% of the Company's common shares outstanding (approximately 6.7 million common shares) at the market price, if and when acquired. During the three months ended March 31, 2003, the Company repurchased 665,600 common shares for gross cost of $32 million. As of April 30, 2003, the Company had repurchased approximately 1.1 million common shares under this plan.

- Increased the quarterly dividend by 20% to $0.15 per common share commencing with the April 1, 2003 payment.

OPERATIONS REVIEW

Production

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

Natural gas production levels stabilized during the first quarter with January volumes of 1,300 mmcf/d and quarterly average production of 1,310 mmcf/d. The stabilization of production volumes confirms the strength of Canadian Natural's asset base and its ability to bring on new reserves at low cost. Natural gas production in April was 1,360 mmcf/d. Canadian Natural's production from the Ladyfern field declined from 82 mmcf/d in January 2003 to 69 mmcf/d during April 2003.

Production of oil and liquids during the first quarter of 2003 was 3 mbbls/d lower than the previous quarter but 49 mbbls/d higher than the corresponding period of last year. Volume increases in North America, when compared with first quarter 2002, reflected additional heavy oil drilling activity and acquired production. North Sea volumes increased primarily as a result of the acquisition of additional interests to consolidate the Company's position in the northern sector of the North Sea. Offshore West Africa volumes increased as production was brought on stream at the Espoir field.

The Company's production composition is as follows:

	Q1 2003		Q4 2002		Q1 2002	
	mboe/d	%	mboe/d	%	mboe/d	%
Natural gas	**218.4**	**48**	227.5	49	175.6	48
Light oil and NGLs	**112.6**	**25**	104.7	22	72.2	20
Pelican Lake oil	**25.1**	**5**	28.6	6	26.6	7
Primary heavy oil	**60.4**	**13**	68.5	15	48.0	13
Thermal heavy oil	**39.5**	**9**	38.8	8	41.6	12
Total	**456.0**	**100**	468.1	100	364.0	100

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, unchanged from previous expectations. Second quarter 2003 production guidance for natural gas is 1,330 to 1,350 mmcf/d of natural gas and 230 to 251 mbbls/d of oil and liquids. During the second quarter, maintenance activities are expected to occur on North American natural gas fields and North Sea platforms. 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)

	Three Months Ended March 31			
	2003		2002	
	Gross	**Net**	Gross	Net
Oil	**124**	**116**	55	47
Natural gas	**261**	**244**	103	95
Dry and abandoned	**24**	**23**	14	13
Subtotal	**409**	**383**	172	155
Stratigraphic test/service wells	**367**	**366**	409	403
Total	**776**	**749**	581	558
Success rate (excluding strat tests/service wells)		**94%**		92%

During the quarter, Canadian Natural drilled a record 749 wells, including 366 stratigraphic test and service wells. Representing the second most active natural gas program in the Company's history, a total of 244 natural gas wells were drilled, a 157% increase over the first quarter results of 2002 when drilling was intentionally deferred in an effort to build inventory to offset anticipated Ladyfern declines.

The Company also drilled 116 net oil wells during the first quarter 2003, representing the third highest activity level in its history. These wells were concentrated in the Company's oil region of North Alberta with 68 primary heavy oil and 26 Pelican Lake wells being drilled. Five high-pressure horizontal thermal wells were also drilled and completed at Primrose as part of the 2003/2004 development strategy of the area.

Finally, 312 stratigraphic test wells were drilled on the oil sands leases in Horizon Oil Sands Project and 51 wells in Primrose and Pelican Lake.

Total success rate for Canadian Natural's drilling program was 94%, excluding stratigraphic test and service wells. This reflects the disciplined approach that the Company takes in its exploitation and development programs and the strength of our asset base. Success rates were enhanced despite increasing the drilling program by about 2.5 times 2002 levels.

Pricing

As a result of political unrest in the Middle East and Venezuela, world oil prices significantly improved in comparison to the previous quarter. During this same time, no appreciable increases in heavy oil differentials occurred, largely the result of lower supplies available to PADD II refiners. As a result, the netbacks received for Canadian Natural's oil and liquids production improved in the first quarter of the year. Similarly, cold weather and decreasing natural gas supplies resulted in significant natural gas price increases. As a result of the usage of financial instruments, the realized price from the sale of crude oil was reduced by $4.11 per bbl in the quarter ended March 31, 2003 ($1.73 per bbl and $0.50 per bbl reduction, respectively, in the quarters ended December 31, 2002 and March 31, 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 $0.50 per mcf in the first quarter of 2003 ($0.07 per mcf reduction and $0.08 per mcf increase, respectively, in the quarters ended December 31, 2002 and March 31, 2002). A comparison of the price received for the Company's North American production is as follows:

	May 5, 2003 Pricing Indications	**Q1 2003**	Q4 2002	Q1 2002
WTI benchmark price (US $/bbl)	**$ 26.49**	**$ 33.80**	$ **28.17**	$ **21.67**
Differential to LLB blend (US $/bbl)	**$ 6.92**	**$ 8.10**	$ **8.13**	$ **5.73**
Condensate benchmark price (US $/bbl)	**$ 27.10**	**$ 33.30**	$ **28.56**	$ **20.83**
NYMEX benchmark price (US $/mmbtu)	**$ 5.69**	**$ 6.64**	$ **3.99**	$ **2.40**
AECO benchmark price (Cdn $/mmbtu)	**$ 6.70**	**$ 7.95**	$ **5.25**	$ **3.35**
Canadian Natural's Wellhead Price(1)				
Light oil and NGLs (Cdn $/bbl)	**$ 33.09**	**$ 38.52**	$ **36.08**	$ **27.83**
Pelican Lake oil (Cdn $/bbl)	**$ 23.73**	**$ 27.52**	$ **25.30**	$ **21.89**
Primary heavy oil (Cdn $/bbl)	**$ 23.38**	**$ 27.41**	$ **24.78**	$ **20.54**
Thermal heavy oil (Cdn $/bbl)	**$ 22.00**	**$ 25.44**	$ **24.11**	$ **19.40**
Natural gas (Cdn $/mcf)	**$ 6.54**	**$ 7.36**	$ **5.04**	$ **3.05**

(1) Including financial instruments

ACTIVITY BY CORE REGION

	Net Undeveloped Land as at March 31, 2003	**Drilling Activity Three months ended March 31, 2003**
	(thousands of net acres)	(net wells)
Northeast British Columbia	**1,467**	**82**
Northwest Alberta	**1,783**	**42**
North Alberta	**5,854**	**277**
South Alberta	**719**	**23**
Southeast Saskatchewan	**159**	**8**
Horizon Oil Sands Project	**117**	**312**
United Kingdom North Sea	**410**	**4**
Offshore West Africa	**943**	**1**
	11,452	**749**

North American Natural Gas

Included in the natural gas drilling count are 33 successful wells in the new Northwest Alberta core region, where Canadian Natural has taken a disciplined approach to development with a view of reducing capital costs and total finding costs. During the first quarter of 2003, many geological and development theories were tested on the southern area where the prolific Cardium formation is prevalent. This work sets up an expanded exploration and development program in 2004 and will allow for a lower-cost exploration and development program when compared with predecessor operations. In particular, the Company has gained better insights into the following key issues:

- The appropriateness of drilling vertical wells in place of traditional, higher cost horizontal wells. The Company has found that areas of medium to high fracture density are better suited to vertical wells where multiple reservoirs can be drilled and hydraulically fractured. These vertical well costs are often about 40% of the cost of a horizontal well, significantly reducing finding costs.
- In areas with low fracture density, horizontal wells with optimal location in stress transfer zones or within folds related to thrusting have better overall effectiveness, again increasing ultimate deliverability and economics of the reserves.
- For those areas with low matrix porosity, drilling results have shown that wells may still be economic if effective fracturing of the structure is present or if it can be achieved with an optimized stimulation program.

Early indications from the first quarter drilling program have exceeded expectations and are very encouraging. The Company will continue to monitor the production performance of the new wells before undertaking a more aggressive development program.

In the Cardium-oriented southern portion of the Northwest Alberta core region, a total of 11 wells targeting natural gas were drilled with a success rate of 100%, providing 29 bcfe of proved reserves. In the Cretaceous-oriented northern portion of this core region, a total of 30 wells targeting natural gas were drilled with a success rate of 74%, providing 58 bcfe of proved reserves. Canadian Natural believes that ultimately, the northern portion could add up to 1.0 trillion cubic feet equivalent of new reserves while the southern portion could add up to 0.75 trillion cubic feet equivalent of new reserves.

In the Northeast British Columbia core region, a total of 81 wells targeting natural gas were drilled, with 36 representing horizontal drilling on the Helmet area development. In this region, a success rate of 96% was achieved. Included in these results were three unsuccessful Slave Point natural gas exploration wells and two unsuccessful exploration wells drilled in the Colville Lake region of the Northwest Territories. Work in this area will now be scaled back pending expansion of natural gas pipeline facilities into the area.

Canadian Natural was also active in its traditional natural gas core regions of North Alberta and South Alberta, drilling 119 and 22 wells targeting natural gas respectively.

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 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 cargoes could be sold on a world-wide basis. Over the long term, as these opportunities come to fruition, Canadian Natural will accelerate development of up to three billion barrels of currently unbooked bitumen resources. As part of this development plan, the Company is currently transitioning its Primrose thermal oil development from low-pressure to high-pressure steaming. New wells are currently being drilled and steaming will commence over the next few months with first increases in production expected in spring 2004.

In the first quarter, the Company drilled 68 heavy oil wells, 26 Pelican Lake oil wells and five high-pressure cyclic steam wells at Primrose. The majority of these wells were drilled late in the first quarter as the drilling program was focused on natural gas early in the quarter. The majority of the North American oil drilling program will commence late in the second quarter of 2003 as the Company's oil areas are more suited for summer drilling.

The Pelican Lake enhanced oil recovery project also continues. This project seeks to significantly increase recovery efficiency on this vast blanket sand in North Alberta. The utilization of emulsion technology offers the best upside potential in ultimate recoverability, however, the drilling of an observation well during the first quarter indicates that while effective, the timeliness of the response is slow. During the remainder of 2003, Canadian Natural will investigate the use of conventional waterflood technologies alone and in conjunction with the emulsion in an effort to maximize value creation through the balancing of recovery factors with timely response.

Horizon Oil Sands Project

Following increased clarity on the Canadian Government's implementation plan for the Kyoto Protocol, 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 is expected this summer with Engineering Design Specification to commence immediately thereafter. Work on a new 30 kilometre access road, including three bridges, has also commenced. It is currently anticipated that the Regulatory Hearing on the Horizon Project application will occur in the summer, with full approvals still targeted for late 2003.

With respect to the Kyoto Protocol, the Company is still working with the Canadian Government to gain certainty on the form of implementation beyond 2012. Such certainty in the principles of implementation would be a requirement prior to final Board of Directors' approval for major construction expenditures in 2004 and beyond. Management remains optimistic that required certainty will be obtained prior to this date.

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.

North Sea

Canadian Natural, as a new operator in the northern North Sea, remains excited about the prospects of extracting additional value from the oil fields surrounding the Ninian and Murchison platforms. During the first quarter, the Company drilled two oil wells targeting reserves stranded against faults within the Ninian field. These wells provided average rates of 3,600 bbls/d of oil with significantly higher flush rates. While it is not anticipated that all results will be this positive, it is an indicator of the potential of the field redevelopment program initiated by Canadian Natural. Similarly, at the Murchison platform a successful producing well has increased production by 1,100 bbls/d. A satellite pool was also drilled off the Murchison platform but encountered no hydrocarbons.

As the new operator of these northern North Sea platforms, Canadian Natural planned for extensive platform turnarounds during the second quarter of 2003. During February 2003, a small oil leak was discovered on the Ninian South Platform, resulting in the shift of this platform's planned turnaround from June to February. This platform also handles all production from the satellite pools at the Columba fields as well as Lyell and Strathspey. During the turnaround, additional equipment inspections discovered degraded pipework between two oil processing modules resulting in the proactive shut-down for a further 39 days commencing March 18, 2003. As a result of unscheduled turnarounds, Canadian Natural's production from the North Sea was reduced by approximately 7,500 bbls/d in the first quarter and 5,800 bbls/d in the second quarter. On an annual basis, Canadian Natural will achieve its production guidance targets despite the second, unanticipated shut-down for pipework improvements due to the recent drilling success and the originally planned summer platform turnaround at Ninian South being completed in February.

Offshore West Africa

The development of the Espoir Field offshore Côte d'Ivoire continued with the drilling of one injector well in the East Espoir structure, consistent with previously disclosed plans. Canadian Natural plans to perforate the upper zone of the East Espoir structure during the second quarter, adding up to 5,000 bbls/d of net new production. In addition, a producing well was completed late in the quarter, adding about 2,400 bbls/d of production.

Subsequent to the quarter-end, the successful drilling of the satellite pool, Acajou, was completed. The Acajou 1X well has been production tested at gross rates of 3,500 bbls/d. The productive, oil-bearing sands encountered in 1X are thin; however, additional sands, which hold significant potential on the northern portion of the structure, were encountered. After the analysis of the 1X test is completed, Canadian Natural will evaluate drilling the northern portion of Acajou and determine if the development of the satellite field is economically feasible.

The Baobab field development also continues in Côte d'Ivoire. During the quarter, quotes for subsea equipment were awarded and bids were received for a Floating Production, Storage and Offtake ("FPSO") vessel. During the second quarter, an FPSO contract is expected to be awarded and tenders for drilling rigs will be accepted. Based upon two successful exploration well tests, Canadian Natural estimates that 200 million barrels of recoverable oil exist within the structure. The Company is planning for an initial start-up date in 2005 at approximately 45,000 bbls/d for the field. Canadian Natural owns approximately 58% of this field.

Extensive 3-D seismic was also shot over parts of offshore Blocks CI-40 and CI-400, reflecting Canadian Natural's belief that the Espoir/Baobab trend continues across these Blocks. Prospects identified through the interpretation of this seismic may lead to additional exploration drilling in future years.

During the quarter, Canadian Natural also continued to reprocess seismic on Block 16 located offshore Angola to optimize the locations 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. Block 16 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 quarter of 2003, strong operational results and product pricing enabled the Company to repay approximately $377 million of long-term debt. The strength of the Canadian dollar during the quarter also reduced carrying values of US dollar based borrowings by an additional $203 million, resulting in a total decrease of long-term debt of $580 million. Corporate debt to cash flow was reduced to 1.2 times versus 1.8 times recorded in 2002, while debt to book capitalization improved to 40% from 46% recorded last quarter.

As at March 31, 2003, Canadian Natural had:

- Approximately $1.2 billion of available unused bank credit lines.
- Fixed/floating interest rate mix of 45%/55%.
- An overall average borrowing cost of approximately 4.9% for the first quarter of 2003.
- 82% of borrowings denominated in US dollars.
- Non-bank based borrowings amounting to 84% of total long-term debt with an average maturity of 15.3 years.

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-back or capital activities not materialize, such allocations of excess cash flow would revert to debt repayment.

In response to the expected demand for oil and natural gas, the related pricing and to protect capital expenditure programs, the Company uses financial instruments to manage exposure to market volatility. The details of these positions are set out in note 8 to the unaudited interim consolidated financial statements.

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 ended March 31, 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		
		March 31 2003	December 31 2002	March 31 2002
Revenue		**$ 1,628**	$ 1,330	$ 717
Cash flow from operations attributable to common shareholders[1]		**$ 906**	$ 777	$ 359
Per common share	– basic	**$ 6.76**	$ 5.81	$ 2.95
	– diluted	**$ 6.53**	$ 5.62	$ 2.85
Net earnings attributable to common shareholders[2]		**$ 428**	$ 209	$ 99
Per common share	– basic	**$ 3.19**	$ 1.56	$ 0.81
	– diluted	**$ 3.03**	$ 1.51	$ 0.79
Capital expenditures, net of dispositions		**$ 813**	$ 292	$ 459

(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 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.

	Three months ended		
($ millions)	March 31 2003	December 31 2002	March 31 2002
Net earnings attributable to common shareholders	$ 428	$ 209	$ 99
Non-cash items:			
Future tax on dividend on preferred securities	(1)	(1)	(1)
Revaluation of preferred securities (net of tax)	(7)	(1)	-
Depletion, depreciation and amortization	375	386	234
Unrealized foreign exchange gain	(119)	-	(12)
Deferred petroleum revenue tax	3	6	1
Future income tax	227	178	38
Cash flow from operations attributable to common shareholders	$ 906	$ 777	$ 359

(2) After dividend and revaluation of preferred securities.

Canadian Natural achieved record levels of net earnings and cash flow for the three months ended March 31, 2003. Net earnings increased to $428 million, up 332% from the prior year and up 105% from the prior quarter. Cash flow increased to $906 million, up 152% from the prior year and up 17% from the prior quarter. The increase in net earnings and cash flow in the first quarter of 2003, compared to the first quarter of 2002, was a result of higher prices for crude oil, NGLs and natural gas and higher production volumes. The increase in production volumes was primarily associated with the acquisition of Rio Alto Exploration Ltd. ("Rio Alto"), the consolidation of working interests in the North Sea and the commencement of production from the Espoir field, located offshore Côte d'Ivoire. Cash flow increased from the prior quarter due to higher product prices. Net earnings increased over the comparable periods due to the increase in product prices and to the strengthening Canadian dollar, resulting in an unrealized foreign exchange gain on the Company's US dollar denominated debt.

ANALYSIS OF QUARTERLY CHANGES IN REVENUE

	Crude oil and NGLs	Natural gas	Midstream	Total
Quarterly Revenue ($ millions)				
March 31, 2002	$ 416	$ 291	$ 10	$ 717
Price variance	66	60	-	126
Volume variance	7	10	-	17
Other variance	-	-	3	3
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**

OPERATING HIGHLIGHTS

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Crude oil and NGLs ($/bbl, except daily production)			
Daily production (bbls/d)	**237,560**	240,596	188,439
Sales price	**$ 35.26**	$ 31.10	$ 24.50
Royalties	**3.56**	3.53	2.28
Production expense	**10.79**	9.10	7.81
Netback	**$ 20.91**	$ 18.47	$ 14.41
Natural gas ($/mcf, except daily production)			
Daily production (mmcf/d)	**1,310**	1,365	1,053
Sales price	**$ 7.25**	$ 5.00	$ 3.06
Royalties	**1.78**	1.09	0.55
Production expense	**0.57**	0.57	0.58
Netback	**$ 4.90**	$ 3.34	$ 1.93
Barrels of oil equivalent ($/boe, except daily production)			
Daily production (boe/d)	**455,952**	468,132	363,990
Sales price	**$ 39.24**	$ 30.54	$ 21.58
Royalties	**6.96**	4.98	2.78
Production expense	**7.27**	6.34	5.73
Netback	**$ 25.01**	$ 19.22	$ 13.07

BUSINESS ENVIRONMENT

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
WTI benchmark price (US $/bbl)	**$ 33.80**	$ 28.17	$ 21.67
Differential to LLB blend (US $/bbl)	**$ 8.10**	$ 8.13	$ 5.73
Condensate benchmark price (US $/bbl)	**$ 33.30**	$ 28.56	$ 20.83
NYMEX benchmark price (US $/mmbtu)	**$ 6.64**	$ 3.99	$ 2.40
AECO benchmark price (Cdn $/mmbtu)	**$ 7.95**	$ 5.25	$ 3.35
US/Canadian dollar exchange rate (US $)	**$ 0.66**	$ 0.64	$ 0.63

In the first quarter of 2003, world oil prices improved significantly due to the uncertainty around the political unrest in Iraq and world supply issues. West Texas Intermediate (“WTI”) averaged US $33.80 per bbl in the first quarter of 2003, up 20% compared to US $28.17 per bbl in the prior quarter, and up 56% from US $21.67 compared to the first quarter of 2002.

PRODUCT PRICES

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Crude oil and NGLs ($/bbl)			
North America	**$ 30.20**	$ 27.57	$ 22.18
North Sea	**$ 50.27**	$ 41.83	$ 33.75
Offshore West Africa	**$ 37.86**	$ 43.15	$ 37.61
Company average	**$ 35.26**	$ 31.10	$ 24.50
Natural gas ($/mcf)			
North America	**$ 7.36**	$ 5.04	$ 3.05
North Sea	**$ 4.03**	$ 3.20	$ 3.77
Offshore West Africa	**$ 3.80**	$ 4.63	$ -
Company average	**$ 7.25**	$ 5.00	$ 3.06
Percentage of revenue (excluding midstream revenue)			
Crude oil and NGLs	**46.9%**	52.3%	58.9%
Natural gas	**53.1%**	47.7%	41.1%

North American and North Sea realized crude oil prices increased from the prior quarter and the comparable period in 2002 due to the increase in the world oil price. In the first quarter of 2003, the heavy oil differential averaged US $8.10 per bbl, just below US $8.13 per bbl in the fourth quarter of 2002 and up 41% from US $5.73 per bbl in the first quarter of 2002. The Offshore West Africa realized crude oil price decreased due to the timing and price received on specific product lifting dates. As a result of the use of financial instruments, the realized price from the sale of crude oil was reduced by $4.11 per bbl in the quarter ended March 31, 2003 ($1.73 per bbl and $0.50 per bbl reduction, respectively, in the quarters ended December 31, 2002 and March 31, 2002).

The natural gas price increased 137% from the comparable period in 2002 and 45% from the prior quarter due to higher seasonal demand as a result of colder temperatures and reduced supply, which resulted in lower than normal storage levels in the North American market. During the first quarter of 2003, storage levels were at historical low levels. AECO and NYMEX prices averaged $7.95 and US $6.64 per mmbtu, respectively, during the quarter ended March 31, 2003 compared to $5.25 and US $3.99 per mmbtu during the previous quarter and $3.35 and US $2.40 per mmbtu in the first 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 $0.50 per mcf in the first quarter of 2003 ($0.07 per mcf reduction and $0.08 per mcf increase, respectively, in the quarters ended December 31, 2002 and March 31, 2002).

DAILY PRODUCTION

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Crude oil and NGLs (bbls/d)			
North America	**173,045**	181,744	152,268
North Sea	**56,963**	51,478	30,910
Offshore West Africa	**7,552**	7,374	5,261
Total	**237,560**	240,596	188,439
Natural gas (mmcf/d)			
North America	**1,265**	1,331	1,026
North Sea	**41**	32	27
Offshore West Africa	**4**	2	-
Total	**1,310**	1,365	1,053
Product mix			
Light crude oil and NGLs	**24.7%**	22.4%	19.9%
Pelican Lake crude oil	**5.5%**	6.1%	7.3%
Primary heavy crude oil	**13.2%**	14.6%	13.2%
Thermal heavy crude oil	**8.7%**	8.3%	11.4%
Natural gas	**47.9%**	48.6%	48.2%

Crude oil and NGLs production increased 26% or 49,121 bbls/d from the comparable period in 2002. Crude oil and NGLs production for the first quarter of 2003 was in line with the Company's guidance of 235,000 to 240,000 bbls/d previously provided.

Crude oil and NGLs production in North America increased 14% or 20,777 bbls/d from the comparable period in 2002 due to the acquisition of Rio Alto, additional heavy oil drilling activity and property acquisitions in the Company's core operating regions in North America in 2002. As anticipated, in the Company's guidance, North American crude oil production declined 5% or 8,699 bbls/d over the prior quarter due to reduced crude oil drilling activity in the fourth quarter of 2002 and the first quarter of 2003, reflecting the increased focus on natural gas drilling.

Crude oil production from the North Sea increased to 84% or 26,053 bbls/d from the comparable period in 2002 and 11% or 5,485 bbls/d from the previous quarter due to the consolidation of the Company's working interests in the North Sea during the past year. Crude oil production from the North Sea was impacted by two unscheduled turnarounds on the Ninian South Platform, which resulted in the Company not reaching its expected North Sea production levels for the first quarter of 2003 of 58,000 to 60,000 bbls/d. The Company had planned for extensive platform turnarounds during the second quarter of 2003. Due to the maintenance required at the Ninian South Platform, the turnaround was accelerated and commenced in the first quarter of 2003. As previously announced on March 26, 2003, crude oil production from 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 Ninian South Platform. On an annual basis the Company expects to achieve its production guidance targets in the North Sea due to recent drilling success and the planned summer platform turnaround work being completed on the Ninian South Platform.

Offshore West Africa crude oil production increased 44% or 2,291 bbls/d from the comparable period in 2002 and 2% or 178 bbls/d from the prior quarter as an additional producing well was completed. Production from this field is anticipated to increase as the Company plans to perforate the upper zone of the East Espoir structure during the second quarter, resulting in an anticipated 5,000 bbls/d of additional production to the Company.

Natural gas production continues to represent the Company's largest product offering and increased 24% or 257 mmcf/d from the comparable period in 2002 as a result of the acquisition of Rio Alto on July 1, 2002 and ongoing drilling activities. Natural gas production decreased 4% or 55 mmcf/d from the prior quarter primarily due to declines at the Ladyfern field in northeast British Columbia. Ladyfern production declined from an average of 127 mmcf/d in the fourth quarter of 2002 to 76 mmcf/d during the first quarter of 2003 as well pressures continue to decline. Overall, natural gas production in the first quarter was in line with the Company's guidance of 1,300 to 1,320 mmcf/d.

Natural gas production in the North Sea increased 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 period in 2002 due to the natural gas pipeline commencing operation in the third quarter of 2002.

The Company expects 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 in 2003, unchanged from previous expectations. Second quarter 2003 production guidance is 1,330 to 1,350 mmcf/d of natural gas and 230,000 to 251,000 bbls/d of crude oil and NGLs. During the second quarter, maintenance activities are expected to occur on North American natural gas fields and North Sea platforms excluding the Ninian South Platform.

ROYALTIES

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Crude oil and NGLs ($/bbl)			
North America	**$ 4.80**	$ 3.82	$ 2.46
North Sea	**$ 0.11**	$ 2.79	$ 1.54
Offshore West Africa	**$ 1.20**	$ 1.35	$ 1.65
Company average	**$ 3.56**	$ 3.53	$ 2.28
Natural gas ($/mcf)			
North America	**$ 1.84**	$ 1.11	$ 0.57
Offshore West Africa	**$ 0.11**	$ 0.15	$ -
Company average	**$ 1.78**	$ 1.09	$ 0.55
Company average ($/boe)	**$ 6.96**	$ 4.98	$ 2.78
Percentage of revenue (excluding financial instruments)			
Crude oil and NGLs	**9.0%**	10.7%	9.1%
Natural gas	**22.9%**	21.4%	18.5%

North America crude oil and NGLs royalties increased as a result of certain heavy oil projects reaching payout in 2002 and becoming subject to higher government royalties. North Sea crude oil royalties as a percentage of revenue decreased in the first quarter 2003 as a result of the elimination of government royalties in the North Sea effective January 1, 2003.

Natural gas royalties as a percentage of revenue increased over both the prior quarter and the comparable prior year period as a result of the strong correlation of royalties to natural gas prices.

PRODUCTION EXPENSE

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Crude oil and NGLs ($/bbl)			
North America	**$ 9.09**	$ 7.34	$ 6.97
North Sea	**$ 15.50**	$ 14.68	$ 10.09
Offshore West Africa	**$ 14.03**	$ 13.68	$ 18.62
Company average	**$ 10.79**	$ 9.10	$ 7.81
Natural gas ($/mcf)			
North America	**$ 0.55**	$ 0.55	$ 0.56
North Sea	**$ 1.09**	$ 1.25	$ 1.33
Offshore West Africa	**$ 2.37**	$ 1.85	$ -
Company average	**$ 0.57**	$ 0.57	$ 0.58
Company average ($/boe)	**$ 7.27**	$ 6.34	$ 5.73

The increase in North American crude oil and NGLs production expense over the comparable three-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. North Sea crude oil production expense increased on a per barrel basis due to the impact of reduced production as a result of the shut down of the Ninian South Platform. Offshore West Africa crude oil production costs for the three months ended March 31, 2003 decreased from the comparable period in 2002 due to increased production from the Espoir field.

Natural gas production expense for the three months ended March 31, 2003 was consistent with the prior quarters.

MIDSTREAM ($ millions)

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Revenue	**$ 18**	$ 15	$ 10
Operating costs	**5**	5	3
Operating cash flow	**13**	10	7
Depreciation	**2**	2	2
Segment earnings before taxes	**$ 11**	$ 8	$ 5

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 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 in the first quarter of 2003 from the comparable periods due to higher electricity prices received in the first quarter of 2003. Revenue from the Company's midstream assets is expected to increase later in 2003 with the expansion of the ECHO pipeline to 72 mbbls/d from 58 mbbls/d.

DEPLETION, DEPRECIATION AND AMORTIZATION[(1)]

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Expense ($ millions)	**$ 373**	$ 384	$ 232
$/boe	**$ 9.09**	$ 8.92	$ 7.08

(1) DD&A does not include midstream operations.

Depletion, depreciation and amortization ("DD&A") in the first quarter of 2003 increased in total and per boe from the first quarter of 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. DD&A decreased from the prior quarter on a total basis due to lower production, but increased on a boe basis due to a higher portion of the Company's production coming from the North Sea segment.

ADMINISTRATION EXPENSE

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Net expense ($ millions)	$ **18**	$ 17	$ 14
$/boe	$ **0.44**	$ 0.41	$ 0.41

Administration expense for the three months ended March 31, 2003 remained relatively stable with the prior quarter in total but increased on a boe basis due to decreased production levels. Administration expense increased from the first quarter of 2002 due to the increased costs associated with the growth in production and the expanding asset base.

INTEREST EXPENSE

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Interest expense, net ($ millions)	**$ 48**	$ 53	$ 28
$/boe	**$ 1.16**	$ 1.22	$ 0.88
Average effective interest rate	**4.9%**	5.0%	4.1%

Interest expense for the three months ended March 31, 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 in the first quarter to repay $377 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		
	March 31 2003	December 31 2002	March 31 2002
Realized foreign exchange loss	**$ 1**	$ 2	$ 2
Unrealized foreign exchange gain	**(119)**	-	(12)
	$ (118)	$ 2	$ (10)

The strengthening of the Canadian dollar to US $0.68 at the end of the first quarter compared to US $0.63 at December 31, 2002 resulted in an unrealized foreign exchange gain on the Company's US dollar denominated debt.

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 months ended March 31, 2003, foreign exchange gains of $62 million (December 31, 2002 - $4 million gain; March 31, 2002 – nil) were included in the foreign currency translation adjustment.

TAXES ($ millions, except income tax rates)

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Taxes other than income tax			
Current	**$ 25**	$ 15	$ 14
Deferred	**3**	6	1
Total	**$ 28**	$ 21	$ 15
Current income tax			
North Sea	**$ 15**	$ (36)	$ 11
Offshore West Africa	**2**	1	1
North America – Current income tax	**16**	-	-
North America – Large corporations tax	**6**	7	4
Total	**$ 39**	$ (28)	$ 16
Future income tax	**$ 227**	$ 178	$ 38
Effective income tax rate	**38.6%**	41.7%	35.0%

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 as a result of higher oil prices and increased production levels.

North Sea current income tax in the first quarter of 2003 increased from the previous year due to the introduction of the supplementary charge of 10% on profits from UK North Sea oil and natural gas production. The North Sea supplementary charge 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 first quarter 2003 increased due to the settlement in the fourth quarter 2002 of certain outstanding matters from prior years 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%.

Taxable income from the conventional 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 its 2003 budget speech, the Canadian Federal Government announced the elimination of the federal Large Corporations Tax ("LCT") over a five-year period. The LCT is currently levied at a rate of 0.225% of the Company's taxable capital employed in Canada. The Federal Government also announced plans to reduce the general corporate income tax rate on income from resource activities over a five-year period from the current rate of 28% to 21%, bringing the resource industry in line with the general corporate income tax rate. As part of the corporate income tax rate reduction, the budget 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. No adjustments for these proposed changes will be made until the plan becomes substantively enacted.

Future income tax expense for the three months ended March 31, 2003 increased over the comparable three month periods due to higher taxable income generated by high product prices.

CAPITAL EXPENDITURES ($ millions)

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Expenditures on property, plant and equipment			
Net property acquisitions	**$ 178**	$ 39	$ 35
Land acquisition and retention	**21**	18	28
Seismic evaluations	**19**	19	25
Well drilling, completion and equipping	**396**	139	207
Pipeline and production facilities	**149**	45	124
Total net reserve replacement expenditures	**$ 763**	$ 260	$ 419
Horizon Oil Sands Project	**41**	19	22
Midstream	**3**	6	10
Abandonments	**3**	4	7
Head office	**3**	3	1
Total net capital expenditures	**$ 813**	$ 292	$ 459
By segment			
North America	**$ 643**	$ 124	$ 390
North Sea	**90**	120	(32)
Offshore West Africa	**30**	16	61
Horizon Oil Sands Project	**41**	19	22
Midstream	**3**	6	10
Abandonments	**3**	4	7
Head office	**3**	3	1
Total	**$ 813**	$ 292	$ 459

During the first quarter of 2003, the Company drilled a record 749 wells, including 366 stratigraphic test and service wells. The Company had a very active natural gas drilling program, drilling a total of 244 successful natural gas wells. North America capital expenditures included the drilling of 42 wells in the new Northwest Alberta core region, where the Company is taking a disciplined approach to the development with a view of reducing capital costs and total finding costs. In the Cardium-oriented southern portion of the Northwest core region, a total of 11 wells targeting natural gas were drilled with a success rate of 100%. In the Cretaceous-oriented northern portion of this core region, a total of 30 wells targeting natural gas were drilled with a success rate of 74%. In the Northeast British Columbia core region, a total of 81 wells targeting natural gas were drilled, including the drilling of three unsuccessful Slave Point natural gas exploration wells. The Company was also active in its traditional natural gas core regions of North Alberta and South Alberta where 119 and 22 wells targeting natural gas were drilled respectively. The Company also drilled 116 successful oil wells during the first quarter. These wells were concentrated in the Company's oil region of North Alberta, where 68 primary heavy oil and 26 Pelican Lake wells were drilled. Five high-pressure horizontal thermal wells were also drilled and completed at Primrose as part of the 2003/2004 development strategy for this area. The Company drilled 312 stratigraphic test wells on the oil sands leases of the Horizon Oil Sands Project and an additional 51 stratigraphic test wells in North Alberta. Capital expenditures also included work on the Horizon Oil Sands Project, where work continues on the Design Basis Memorandum ("DBM") that is anticipated to be completed early in the summer. The Engineering Design Specification will commence immediately after the completion of the DBM. Work has commenced on the access road, including the construction of three bridges.

North Sea capital expenditures included successfully drilling two oil wells from the Ninian platforms and one well from the Murchison platform. In addition, a satellite pool was drilled off the Murchison platform but encountered no hydrocarbons.

Offshore West Africa capital expenditures included the continued development of the Espoir field located offshore Côte d'Ivoire with the drilling of one injector well in the East Espoir structure. The Company plans to perforate the upper zone of the East Espoir structure during the second quarter of 2003. Development of the Baobab field continued during the first quarter with quotes for subsea equipment being awarded and bid requests received for a Floating Production, Storage and Offtake vessel. The first quarter also saw extensive 3-D seismic shot over parts of offshore Blocks CI-40 and CI-400 and the Company continues to reprocess seismic on Block 16, located offshore Angola. The Company's current plans regarding Block 16 envision the drilling of either the Zenza or the Omba prospect during the fourth quarter of 2003.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)

	Three Months Ended		
	March 31 2003	December 31 2002	March 31 2002
Working capital deficit	**$ 318**	$ 14	$ 84
Long-term debt	**3,494**	4,074	2,658
Total	**$ 3,812**	$ 4,088	$ 2,742
Shareholders' equity			
Preferred securities	**$ 118**	$ 126	$ 128
Share capital	**2,327**	2,304	1,739
Retained earnings	**2,801**	2,414	1,992
Foreign currency translation adjustment	**16**	24	69
Total	**$ 5,262**	$ 4,868	$ 3,928
Debt to cash flow(1)	**1.2x**	1.8x	1.6x
Debt to book capitalization	**39.9%**	45.6%	40.4%
Debt to market capitalization	**33.8%**	38.9%	29.2%
After tax return on average common shareholders' equity(1)	**20.3%**	13.8%	14.6%
After tax return on average capital employed(1)	**12.6%**	8.9%	9.7%

(1) Based on trailing 12-month activity.

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 first quarter long-term debt was reduced by $580 million. Higher than budgeted prices received for the Company's products are expected to result in 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 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 the Company's 2003 average production volumes. 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.

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 share, basic)	Net earnings [(2)] ($ millions)	Net earnings [(2)] (per share, basic)
Price changes				
Oil – WTI US $1.00/bbl[(3)]				
Excluding financial derivatives	$96	$0.72	$67	$0.50
Including financial derivatives	$67	$0.50	$47	$0.35
Natural gas – AECO Cdn $0.10/mcf[(3)]				
Excluding financial derivatives	$31	$0.23	$18	$0.14
Including financial derivatives	$27	$0.20	$16	$0.12
Volume changes				
Oil – 10,000 bbls/d	$73	$0.54	$31	$0.23
Natural gas – 10 mmcf/d	$20	$0.15	$9	$0.07
Foreign currency rate change				
$0.01 change in Cdn $ in relation to US $[(3)]				
Excluding financial derivatives	$64	$0.48	$22	$0.16
Including financial derivatives	$58	$0.43	$18	$0.13
Interest rate change - 1%	$11	$0.08	$11	$0.08

(1) The sensitivities are calculated based on 2003 first quarter results.
(2) Attributable to common shareholders.
(3) For details of financial derivatives in place, see the interim consolidated financial statement note 8.

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		
	March 31 2003	December 31 2002	March 31 2002
Daily production (boe/d)	**455,952**	468,132	363,990
Sales price	**$ 39.24**	$ 30.54	$ 21.58
Royalties	**6.96**	4.98	2.78
Production expense	**7.27**	6.34	5.73
Netback	**25.01**	19.22	13.07
Midstream contribution	**(0.32)**	(0.24)	(0.22)
Administration	**0.44**	0.41	0.41
Interest	**1.16**	1.22	0.88
Foreign exchange loss	**0.02**	0.05	0.07
Taxes other than income tax (current)	**0.63**	0.35	0.41
Current income tax (North Sea)	**0.37**	(0.83)	0.33
Current income tax (Offshore West Africa)	**0.05**	0.01	0.02
Current income tax (North America)	**0.39**	-	-
Current income tax (Large corporations tax)	**0.13**	0.16	0.13
Cash flow	**$ 22.14**	$ 18.09	$ 11.04

	Three Months Ended March 31, 2003			
	North America	North Sea	Offshore West Africa	Total
Crude oil and NGLs ($/bbl, except daily production)				
Daily production (bbls/d)	173,045	56,963	7,552	237,560
Sales price	$ 30.20	$ 50.27	$ 37.86	$ 35.26
Royalties	4.80	0.11	1.20	3.56
Production expense	9.09	15.50	14.03	10.79
Netback	$ 16.31	$ 34.66	$ 22.63	$ 20.91
Natural gas ($/mcf, except daily production)				
Daily production (mmcf/d)	1,265	41	4	1,310
Sales price	$ 7.36	$ 4.03	$ 3.80	$ 7.25
Royalties	1.84	-	0.11	1.78
Production expense	0.55	1.09	2.37	0.57
Netback	$ 4.97	$ 2.94	$ 1.32	$ 4.90
Barrels of oil equivalent ($/boe, except daily production)				
Daily production (boe/d)	383,952	63,764	8,236	455,952
Sales price	$ 37.94	$ 47.49	$ 36.61	$ 39.24
Royalties	8.23	0.09	1.16	6.96
Production expense	5.92	14.55	14.04	7.27
Netback	$ 23.79	$ 32.85	$ 21.41	$ 25.01

FINANCIAL STATEMENTS

consolidated balance sheets

(millions of Canadian dollars, unaudited)	**March 31 2003**	December 31 2002
ASSETS		
Current assets		
Cash	**$ 17**	$ 30
Accounts receivable and other	**999**	745
	1,016	775
Property, plant and equipment (net)	**12,858**	12,500
Deferred charges	**79**	84
	$ 13,953	$ 13,359
LIABILITIES		
Current liabilities		
Accounts payable	**$ 508**	$ 337
Accrued liabilities	**802**	428
Current portion of long-term debt (note 2)	**24**	24
	1,334	789
Long-term debt (note 2)	**3,494**	4,074
Future site restoration	**438**	440
Future income tax (note 3)	**3,425**	3,188
	8,691	8,491
SHAREHOLDERS' EQUITY		
Preferred securities	**118**	126
Share capital (note 4)	**2,327**	2,304
Retained earnings	**2,801**	2,414
Foreign currency translation adjustment (note 5)	**16**	24
	5,262	4,868
	$ 13,953	$ 13,359

consolidated statements of earnings

(millions of Canadian dollars, except per share amounts, unaudited)	Three Months Ended March 31 **2003**	2002
Revenue	**$ 1,628**	$ 717
Less: royalties	**(286)**	(91)
	1,342	626
Expenses		
Production	**303**	191
Depletion, depreciation and amortization	**375**	234
Administration	**18**	14
Interest	**48**	28
Foreign exchange gain	**(118)**	(10)
	626	457
Earnings before taxes	**716**	169
Taxes other than income tax	**28**	15
Current income tax (note 3)	**39**	16
Future income tax (note 3)	**227**	38
Net earnings	**422**	100
Dividend on preferred securities (net of tax)	**(1)**	(1)
Revaluation of preferred securities (net of tax)	**7**	-
Net earnings attributable to common shareholders	**$ 428**	$ 99
Net earnings per common share attributable to common shareholders (note 6)		
Basic	**$ 3.19**	$ 0.81
Diluted	**$ 3.03**	$ 0.79

consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Three Months Ended March 31 **2003**	2002
Balance – beginning of period	**$ 2,414**	$ 1,908
Net earnings	**422**	100
Dividend on common shares (note 4)	**(20)**	(15)
Purchase of common shares (note 4)	**(21)**	-
Dividend on preferred securities (net of tax)	**(1)**	(1)
Revaluation of preferred securities (net of tax)	**7**	-
Balance – end of period	**$ 2,801**	$ 1,992

consolidated statements of cash flows

(millions of Canadian dollars, except per share amounts, unaudited)	Three Months Ended March 31 **2003**	2002
Operating activities		
Net earnings	**$ 422**	$ 100
Non-cash items		
Depletion, depreciation and amortization	**375**	234
Deferred petroleum revenue tax	**3**	1
Future income tax	**227**	38
Unrealized foreign exchange gain	**(119)**	(12)
Cash flow provided from operations	**908**	361
Deferred charges	**5**	-
Net change in non-cash working capital	**(82)**	(58)
	831	303
Financing activities		
Repayment of bank credit facilities	**(372)**	(651)
Issue of US debt securities	**-**	642
Repayment of lease obligations	**(5)**	
Issue of capital stock	**34**	42
Purchase of common shares	**(32)**	-
Dividend on common shares	**(17)**	(12)
Dividend on preferred securities	**(2)**	(2)
Net change in non-cash working capital	**2**	(7)
	(392)	12
Investing activities		
Expenditures on property, plant and equipment	**(820)**	(515)
Net proceeds on sale of property, plant and equipment	**7**	56
Net expenditures on property, plant and equipment	**(813)**	(459)
Net change in non-cash working capital	**361**	165
	(452)	(294)
(Decrease) increase in cash	**(13)**	21
Cash – beginning of period	**30**	15
Cash – end of period	**$ 17**	$ 36

Supplemental disclosure of cash flow information (note 7)

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. 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 for this presentation dated May 7, 2003. 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. LONG-TERM DEBT

	March 31 2003	December 31 2002
Bank credit facilities		
Canadian dollar debt	**$ 356**	$ 728
US dollar debt (2003 – US $150 million, 2002 – US $150 million)	**220**	237
Medium-term notes	**250**	250
Senior unsecured notes (2003 – US $318 million, 2002 – US $318 million)	**478**	499
US dollar debt securities (2003 – US $1,500 million, 2002 – US $1,500 million)	**2,204**	2,369
Obligations under capital leases	**10**	15
	3,518	4,098
Less: current portion of long-term debt	**24**	24
	$ 3,494	$ 4,074

Bank credit facilities

At March 31, 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 2003, the Company repaid and cancelled a $500 million acquisition term credit facility.

In addition to the outstanding debt, letters of credit aggregating $19 million have been issued.

Senior unsecured notes

On May 1, 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.

3. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended March 31			
		2003		2002
Current income tax expense				
Current income tax – North America	**$**	**16**	$	-
Large corporations tax – North America		**6**		4
Current income tax – North Sea		**15**		11
Current income tax – Offshore West Africa		**2**		1
		39		16
Future income tax expense		**227**		38
Income taxes	**$**	**266**	$	54

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.

4. SHARE CAPITAL

Issued	**March 31, 2003**		
Common shares	**Number of shares** (thousands)		**Amount**
Balance – beginning of period	**133,776**	**$**	**2,304**
Issued upon exercise of stock options	**1,068**		**34**
Purchase of shares under Normal Course Issuer Bid	**(666)**		**(11)**
Balance – end of period	**134,178**	**$**	**2,327**

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 March 31, 2003, the Company had purchased 665,600 common shares for a total cost of $32 million. The excess cost over book value of the shares purchased was applied to retained earnings.

Subsequent to March 31, 2003, the Company has purchased an additional 420,000 common shares for a total cost of $21 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	**March 31, 2003**		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**12,882**	**$**	**37.13**
Granted	**76**	**$**	**47.32**
Exercised	**(1,068)**	**$**	**32.18**
Forfeited	**(82)**	**$**	**44.07**
Outstanding – end of period	**11,808**	**$**	**37.60**
Exercisable – end of period	**3,966**	**$**	**33.68**

Stock-based compensation costs

The Company accounts for its stock-based compensation using the intrinsic value method and as a result, no compensation costs have been recorded in the consolidated financial statements for stock options granted or exercised. Had the Company adopted the fair value based method of accounting, the compensation costs, along with the pro forma net earnings attributable to common shareholders and pro forma net earnings attributable to common shareholders per common share of the Company would be as follows:

	Three Months Ended March 31			
		2003		2002
Stock-based compensation costs	**$**	**7**	$	6
Net earnings attributable to common shareholders				
As reported	**$**	**428**	$	99
Pro forma	**$**	**421**	$	93
Net earnings per common share attributable to common shareholders				
Basic				
As reported	**$**	**3.19**	$	0.81
Pro forma	**$**	**3.14**	$	0.77
Diluted				
As reported	**$**	**3.03**	$	0.79
Pro forma	**$**	**2.98**	$	0.75

The stock-based compensation costs are recognized over the vesting period of the stock options granted. The pro forma amounts shown above do not include the stock-based compensation costs associated with stock options granted prior to January 1, 2000.

The fair value of each stock option granted during the quarter is estimated on the date of grant using the Black-Scholes option pricing model based on the following:

	Three Months Ended March 31	
	2003	2002
Fair value of options granted (per share)		
Directors, officers and executives	**$ -**	$ 14.49
Other employees	**$ 11.10**	$ 11.70
Risk-free interest rate	**3.8%**	3.9%
Expected life (years)		
Directors, officers and executives	**-**	5.5
Other employees	**4.0**	3.6
Expected volatility	**26%**	38%
Expected dividend yield	**1.3%**	1.3%

5. 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.

	March 31, 2003
Balance – beginning of period	**$ 24**
Unrealized loss on translation of net investment	**(60)**
Hedge of net investment with US dollar denominated debt (net of tax)	**52**
Balance – end of period	**$ 16**

6. NET EARNINGS PER COMMON SHARE ATTRIBUTABLE TO COMMON SHAREHOLDERS

	Three Months Ended March 31	
	2003	2002
Weighted average common shares outstanding (thousands)		
Basic	**134,036**	121,610
Effect of dilutive stock options	**2,668**	2,497
Assumed settlement of preferred securities with common shares	**2,420**	2,668
Diluted	**139,124**	126,775
Net earnings attributable to common shareholders	**$ 428**	$ 99
Dividend on preferred securities (net of tax)	**1**	1
Revaluation of preferred securities (net of tax)	**(7)**	-
Diluted net earnings attributable to common shareholders	**$ 422**	$ 100
Net earnings per common share attributable to common shareholders		
Basic	**$ 3.19**	$ 0.81
Diluted	**$ 3.03**	$ 0.79

7. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Three Months Ended March 31	
	2003	2002
Interest paid	**$ 42**	$ 26
Taxes (recovered) paid	**$ (7)**	$ 29

8. 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 May 7, 2003:

	Remaining Term	Volume	Average Price	Index
Oil				
Brent differential swaps	Apr. 2003 – Dec. 2003	15,000 bbls/d	US $1.00	Dated Brent/WTI
	Jan. 2004 – Dec. 2004	8,000 bbls/d	US $1.15	Dated Brent/WTI
Oil price collars	Apr. 2003 – Jun. 2003	110,667 bbls/d	US $22.48 – US $28.06	WTI
	Jul. 2003 – Sep. 2003	73,333 bbls/d	US $23.45 – US $28.75	WTI
	Oct. 2003 – Dec. 2003	40,000 bbls/d	US $24.00 – US $30.17	WTI

	Remaining Term	Volume	Average Price	Index
Natural gas				
NYMEX collar	Apr. 2003 – Oct. 2003	30,000 mmbtu/d	US $2.88 – US $6.12	NYMEX
Sumas fixed	Apr. 2003 – Oct. 2003	10,000 mmbtu/d	Cdn $2.85	Sumas
AECO collars	Apr. 2003 – Jun. 2003	240,000 GJ/d	Cdn $4.13 – Cdn $6.11	AECO
	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	Apr. 2003 – May 2003	US $4/month	1.43 – 1.53
	Apr. 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	Apr. 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	Apr. 2003 – Jul. 2004	US $200	6.70%	LIBOR + 2.09%
	Apr. 2003 – Jul. 2006	US $200	6.70%	LIBOR + 1.58%
	Apr. 2003 – Jan. 2005	US $200	7.20%	LIBOR + 3.00%
	Apr. 2003 – Jan. 2007	US $200	7.20%	LIBOR + 2.23%
	Apr. 2003 – Oct. 2012	US $200	5.45%	LIBOR + 0.81%
Swaps – floating to fixed	Apr. 2003 – Mar. 2004	Cdn $100	5.08%	CDOR
	Apr. 2003 – Mar. 2007	Cdn $16	7.36%	CDOR

9. SEGMENTED INFORMATION

	Three Months Ended March 31	
	2003	2002
Revenue		
North America	**$ 1,310**	$ 586
North Sea	**273**	103
Offshore West Africa	**27**	18
Midstream	**18**	10
	$ 1,628	$ 717
Net Earnings		
North America	**$ 361**	$ 73
North Sea	**51**	20
Offshore West Africa	**4**	4
Midstream	**6**	3
	422	100
Dividend on preferred securities (net of tax)	**(1)**	(1)
Revaluation of preferred securities (net of tax)	**7**	-
Net Earnings Attributable to Common Shareholders	**$ 428**	$ 99
Additions to Property, Plant and Equipment		
North America	**$ 643**	$ 390
North Sea	**107**	(55)
Offshore West Africa	**30**	61
Horizon Oil Sands Project	**41**	22
Midstream	**3**	10
Abandonments	**3**	7
Other	**3**	1
	$ 830	$ 436

	Property, Plant and Equipment		Total Assets	
	March 31 2003	December 31 2002	**March 31 2003**	December 31 2002
Segmented Assets				
North America	**$ 10,610**	$ 10,252	**$ 11,472**	$ 10,917
North Sea	**1,213**	1,277	**1,388**	1,427
Offshore West Africa	**540**	518	**573**	549
Horizon Oil Sands Project	**270**	229	**270**	229
Midstream	**197**	196	**222**	209
Other	**28**	28	**28**	28
	$ 12,858	$ 12,500	**$ 13,953**	$ 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 March 31, 2003:	
Interest coverage (times)	
Net earnings	9.5[(1)]
Cash flow from operations attributable to common shareholders	17.0[(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 March 31, 2003, would be 9.1x and the cash flow coverage ratio for the 12-month period ended March 31, 2003 would be 16.0x.

2003 SECOND QUARTER RESULTS

2003 second quarter results are scheduled for release Wednesday, August 6, 2003. A conference call will be held that day at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time.

CORPORATE PROFILE

Canadian Natural is one of the largest independent crude oil and natural gas producers in the world. We achieved this status through continued application of our value creation objectives and defined growth strategy. We have a low-cost, diversified combination of assets in North America, the North Sea and Offshore West Africa, which enables us to generate significant value, even in challenging economic environments. Our balanced mix of natural gas, light oil and heavy oil production, combined with a major oil sands mining project, represents one of the strongest and most diverse asset portfolios of any energy producer in the world.

CORPORATE INFORMATION

Officers

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Chairman

N. Murray Edwards
Vice-Chairman

John G. Langille
President

Steve W. Laut
Chief Operating Officer

Brian L. Illing
Executive Vice-President, Exploration

Réal M. Cusson
Senior Vice-President, Marketing

Réal J.H. Doucet
Senior Vice-President, Oil Sands

Allen M. Knight
Senior Vice-President, International and Corporate Development

Tim S. McKay
Senior Vice-President, North American Operations

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Senior Vice-President, Finance

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William R. Clapperton
Vice-President, Regulatory, Stakeholder & Environmental Affairs

Cameron S. Kramer
Vice-President, Field Operations

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