Canadian Natural

Press Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES
RECORD 2003 RESULTS AND PROPOSES TWO FOR ONE STOCK SPLIT
CALGARY, ALBERTA – February 25, 2004 – FOR IMMEDIATE RELEASE

In commenting on fourth quarter and year-end 2003 results, Canadian Natural's Chairman, Allan Markin, stated "This was another record year, reflecting the execution of our defined growth strategy to create shareholder value. Record annual cash flow and earnings and solid fourth quarter results were a direct result of drilling success and operational efficiency. We have made significant progress on our larger, future-growth projects while maintaining our focus on existing assets, both in North America and internationally."

"As we look into 2004, we see continued opportunities to significantly add value. Our 2004 natural gas exploration and development program looks strong as we continue to capitalize on program advancements made in 2003. Cost reduction strategies in Northwest Alberta and targeted new exploration horizons there and in Northeast British Columbia have met planned expectations early in this year's drilling season."

"Our heavy oil marketing strategy is gaining momentum, with the current 34,000 barrel per day test of Synbit drawing the attention of other refiners within PADD II. Our acquisition of additional heavy oil properties in Alberta announced February 18, 2004 helps solidify our position as a market leader, meaning that we will be a significant beneficiary as U.S. markets for heavy oil expand."

"Project Horizon continues on schedule. We recently received Joint Panel and Alberta Provincial Cabinet approvals for the project and expect remaining regulatory approvals in the first half of 2004. We also expect to determine final cost expectations through continued project definition and our defined execution strategy. This, combined with the definition of our financing plans, means we will seek sanction from the Board of Directors during the second half of this year. The balance sheet exits 2003 in a very strong position with debt to book capitalization at only 32%. During 2004, we look to further strengthen our ability to fund Project Horizon. Based upon current strip pricing, we estimate 2004 cash flow of between $3.0 billion and $3.2 billion, with a capital expenditure budget of $2.75 billion to $2.95 billion."

HIGHLIGHTS

- Record annual net earnings of $1.4 billion ($10.48 per common share) compared with $0.6 billion ($4.46 per common share) in 2002. Adjusted annual net earnings from operations of $1.0 billion ($7.43 per common share) compared with $0.6 billion ($4.51 per common share) in 2002.
- Record annual cash flow of $3.2 billion ($23.54 per common share) compared with $2.3 billion ($17.63 per common share) in 2002.
- Continued strengthening of the Company's financial position, with debt to book capitalization at the end of 2003 falling to 32% versus 46% at the end of 2002 and a debt to EBITDA ratio of 0.8 times in 2003 compared to 1.6 times in 2002.
- Fourth quarter net earnings of $251 million ($1.87 per common share) compared with $209 million ($1.56 per common share) for the fourth quarter of 2002 and $203 million ($1.51 per common share) in the third quarter of 2003. Adjusted net earnings from operations amounted to $202 million ($1.51 per common share) compared with $208 million ($1.56 per common share) in the fourth quarter of 2002 and $215 million ($1.60 per common share) in the third quarter of 2003.
- Continued strong fourth quarter cash flow of $734 million ($5.48 per common share) compared with $777 million ($5.81 per common share) in the fourth quarter of 2002 and $758 million ($5.62 per common share) in the third quarter of 2003.

- Record fourth quarter crude oil and NGLs sales of over 244 mbbl/d, at the mid point of the Company's guidance.
- Continued strong fourth quarter natural gas sales of 1.27 bcf/d, equal to 46% of production, also at the mid point of the Company's guidance.
- Reduction of 5% in production expense per boe in the fourth quarter from the third quarter with natural gas production expense remaining constant and crude oil and NGLs production expense reducing by $0.69 per barrel or 7%.
- Utilizing a qualified independent evaluation on 100% of the Company's reserves with a constant pricing model:
  - Proved reserves, net of royalties, replaced production by 129% at a finding and onstream cost of $12.34 per boe with additional costs to develop of $1.51 per boe.
  - Proved and probable reserves, net of royalties, replaced production by 308% at a finding and onstream cost of $5.18 per boe with additional costs to develop of $1.60.
  - At the end of 2003, proved and probable crude oil and NGLs reserves before royalties amounted to 1.5 billion barrels, a 25% increase from the prior year, with natural gas reserves amounting to 3.8 tcf, a 5% increase over 2002.
  - Proved and probable reserves per common share have increased by 34% to 15.8 boe/share on a before royalties basis.
- Horizon Oil Sands Project received regulatory approvals from the Joint Panel in early January 2004. Third and final phase of pre-construction engineering, Engineering Design Specification ("EDS"), continues with completion expected in the second half of 2004. No reserves have been booked with respect to this project.
- The Baobab development, located offshore Côte d'Ivoire, continues on time and on budget. Development drilling and fabrication of the Floating Production Storage and Offtake ("FPSO") vessel commenced during the fourth quarter.
- Under its Normal Course Issuer Bid, the Company purchased 330,000 of its common shares during the fourth quarter for a total cost of $21 million. During 2003, the Company purchased approximately 2.7 million of its common shares for a total cost of $144 million (average cost - $52.51/share), resulting in the Company ending the year with less outstanding common shares than it started the year. The Normal Course Issuer Bid has been extended to January 2005, allowing for the repurchase of up to 6.7 million shares through facilities of the Toronto Stock Exchange and the New York Stock Exchange.
- Fourth straight year of dividend increases. The 2004 quarterly dividends will increase 33% from $0.15 per common share to $0.20 per common share commencing with the April 1, 2004 dividend payment.
- To increase the liquidity of its common shares, the Board of Directors will recommend to the shareholders that the Company's common shares be subdivided on the basis of 2:1. The proposal will be voted on at the Annual and Special Meeting of the Shareholders to be held on May 6, 2004.

CORPORATE ANNOUNCEMENT

- The Board of Directors is pleased to announce the appointment of Ms. Catherine (Kay) M. Best, FCA to the Board of Directors in November 2003 and her subsequent appointment to the Audit Committee. Ms. Best is currently Senior Vice President, Risk Management and CFO for the Calgary Health Region. Before joining the Calgary Health Region in 2000, Ms. Best was employed with a major international accounting firm for 19 years, 10 of which was as Corporate Audit Partner. Her practice and developed expertise focused on oil and gas and related cross border industries. Through her training and expertise Ms. Best qualifies as an "audit committee financial expert" on the Audit Committee of the Board of Directors of the Corporation.

ADJUSTED NET EARNINGS FROM OPERATIONS

The following reconciliation lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results 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 its business segments.

($ millions, except per common share amounts)

	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Net earnings attributable to common shareholders as reported	**$ 251**	$ 203	$ 209	**$ 1,407**	$ 570
Unrealized foreign exchange gain [1]	**(64)**	(9)	-	**(256)**	(35)
Unrealized foreign exchange gain on preferred securities[1]	**(4)**	-	(1)	**(18)**	(1)
Effect of statutory tax rate changes on future income tax liabilities[2]	**(31)**	-	-	**(278)**	13
Stock-based compensation expense [3]	**43**	21	-	**136**	-
Reduction in carrying value of foreign assets[4]	**7**	-	-	**7**	30
Adjusted net earnings from operations attributable to common shareholders	**$ 202**	$ 215	$ 208	**$ 998**	$ 577
Per share – basic	**$ 1.51**	$ 1.60	$ 1.56	**$ 7.43**	$ 4.51
– diluted	**$ 1.50**	$ 1.58	$ 1.51	**$ 7.30**	$ 4.37

[1] *Unrealized foreign exchange gains and losses result primarily from the translation of long-term debt and preferred securities to period end exchange rates and 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 is 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 second quarter, a Canadian province reduced corporate income tax rates. During the year ended December 31, 2002, the United Kingdom increased income taxes applicable to the crude oil and natural gas industry and a Canadian province reduced corporate income tax rates. Fourth quarter 2003 recovery represents changes in timing of tax liability reversals.*

[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. An additional expense of $43 million after taxes ($63 million before taxes) was recognized in the fourth quarter of 2003 and $21 million after taxes ($32 million before taxes) in the third quarter of 2003.*

[4] *Following an unsuccessful exploratory well drilled offshore France in 2003 and the decision to allow the lease to expire with no further exploration, all capitalized costs related to the France well and lease were charged to net earnings attributable to common shareholders. Following an unsuccessful exploratory well drilled in 2002 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 attributable to common shareholders.*

OPERATIONS REVIEW

In this document, reference is made to oil and gas in common units called barrel of oil equivalent ("boe"). A boe is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6mcf:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6mcf:1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

Production, Before Royalties

Quarterly and annual production of both natural gas and crude oil and NGLs were within guidance parameters previously announced. Crude oil and NGLs production for the year ended December 31, 2003 increased approximately 27.1 mbbl/d or 13% and natural gas production increased by 67 mmcf/d or 5% from the previous year.

During the fourth quarter, crude oil and NGLs production declined 2.8 mbbl/d from third quarter levels, reflecting production declines at Pelican Lake, as well as drilling delays and maintenance downtime reducing North Sea production as partially offset by increases in conventional heavy oil and Offshore West Africa production.

As expected, natural gas production levels decreased from the third quarter to 1,270 mmcf/d. This reflects the normal production declines on the portion of Canadian Natural's asset base that is suitable for winter-only access. Approximately 11 mmcf/d of Canadian Natural's natural gas production was shut in September 1, 2003 due to bitumen conservation measures undertaken by the Alberta Energy and Utilities Board (EUB). In January, the Company applied for further exemptions which have reduced the shut-in volume to 6 mmcf/d. On January 2, 2004 the EUB staff submission group released recommendations to shut in additional gas volumes in the Athabasca region. The EUB will be convening an interim hearing on March 8, 2004 to assess whether additional gas production is associated with potentially recoverable bitumen. Canadian Natural has an additional 11 mmcf/d of production that could be at risk of being shut in as a result of this hearing. The Alberta Department of Energy ("ADOE") has announced an interim assistance plan under which Alberta crown royalty deferrals are granted at a rate of $0.60/mcf of shut-in production.

The Company's production composition is as follows:

	Q4 2003		Q3 2003		Q4 2002	
	mboe/d	**%**	mboe/d	%	mboe/d	%
Natural gas	**211.7**	**46**	214.9	46	227.5	49
Light crude oil and NGLs	**115.4**	**25**	118.9	26	104.7	22
Pelican Lake crude oil	**21.5**	**5**	23.5	5	28.6	6
Primary heavy crude oil	**71.0**	**16**	68.3	15	68.5	15
Thermal heavy crude oil	**36.4**	**8**	36.3	8	38.8	8
Total	**456.0**	**100**	461.9	100	468.1	100

The Company expects production levels in the first quarter of 2004 to average 1,285 to 1,315 mmcf/d of natural gas and 245 to 265 mbbl/d of crude oil and NGLs. This results in expected annual 2004 production levels of approximately 1,320 to 1,395 mmcf/d of natural gas (2003 – 1,299 mmcf/d) and approximately 263 to 283 mbbl/d of crude oil and NGLs (2003 – 242 mbbl/d).

These production expectations incorporate the February 2004 acquisition of Petrovera and are based upon revised capital spending expectations of $2.75 to $2.95 billion, made concurrent with the acquisition. For further guidance details, please refer to Canadian Natural's website at www.cnrl.com/investor/guidance.htm.

DRILLING ACTIVITY (number of wells)

	Year Ended December 31			
	2003		2002	
	Gross	**Net**	Gross	Net
Oil	**490**	**458**	316	264
Natural gas	**841**	**777**	183	162
Dry	**126**	**118**	32	27
Subtotal	**1,457**	**1,353**	531	453
Stratigraphic test/service wells	**447**	**440**	456	447
Total	**1,904**	**1,793**	987	900
Success rate (excluding strat test/service wells)		**91%**		94%

During the fourth quarter, Canadian Natural drilled 94 net crude oil wells concentrated in the Company's heavy crude oil areas of North Alberta and 240 net natural gas wells. The natural gas wells included 125 shallow wells in South Alberta, which have productive rates from 50 mcf/d to 200 mcf/d, as well as 41 net wells in Northwest Alberta and 46 net wells in North Alberta. Many of these wells were drilled late in the fourth quarter and therefore did not add significantly to fourth quarter production levels and did not achieve enough production history to warrant significant reserve additions. The total success rate for Canadian Natural's drilling program was 91% for 2003, excluding stratigraphic test/service wells.

During the year, the Company drilled a total of 1,793 wells, almost twice 2002 levels. In particular, natural gas drilling increased to almost five times the level of activity experienced in the prior year, while crude oil drilling increased 73%. The increase in natural gas drilling is reflective of the Company's proactive decision to defer drilling prospects in 2002 in anticipation of Ladyfern production declines.

During 2003, the Company drilled 440 net stratigraphic test/service wells on the oil sands leases in the Horizon Oil Sands Project and in North Alberta.

Pricing

Product pricing remained strong during the fourth quarter for both crude oil and natural gas as measured in U.S. dollars. West Texas Intermediate ("WTI") benchmark pricing was up versus both the previous quarter and last year, while NYMEX natural gas pricing was 10% below third quarter but 15% higher than the corresponding quarter of last year. However due to the strength of the Canadian dollar in relation to the U.S. dollar, crude oil and natural gas benchmark prices as measured in Canadian dollars were lower than both the previous quarter and last year.

As expected, heavy oil differentials widened during the fourth quarter due to normal seasonality. Detailed reviews of benchmark pricing as well as Canadian Natural's sensitivity to currency exchange rates are available in Management's Discussion and Analysis. Canadian Natural continues to deliver on its heavy oil marketing strategy and in particular its bitumen diluted with synthetic light crude oil or "Synbit" product. The Company is currently marketing 34,000 bbl/d of Synbit to refiners located in the U.S. Midwest. The Company plans to expand this effort throughout 2004 to build a solid new market for heavy and synthetic crudes. This demand expansion will enable Canadian Natural to expand heavy oil production without impairing sales prices.

The Company utilizes hedges on a portion of its production in an effort to ensure operating cash flows are sufficient to cover capital expenditures. Generally, costless collars are utilized against benchmark commodity prices as well as currency exposures. The details of these hedge positions are reported in note 9 of the consolidated financial statements.

First quarter 2004 indicative prices as at February 24, 2004 include a one year forward reference WTI price of US$31.46/bbl, a NYMEX natural gas price of US$5.28/mmbtu and a Lloyd Blend heavy oil differential of US$8.80/bbl. The Bank of Canada noon day exchange rate for this date was US$0.7530 equals C$1.00.

ACTIVITY BY CORE REGION

	Net Undeveloped Land as at December 31, 2003 (thousands of net acres)	Drilling Activity year ended December 31, 2003 (net wells)
Northeast British Columbia	**1,566**	**106**
Northwest Alberta	**1,681**	**121**
North Alberta	**5,627**	**717**
South Alberta	**673**	**430**
Southeast Saskatchewan	**147**	**27**
Horizon Oil Sands Project	**117**	**370**
North Sea	**1,920**	**18**
Offshore West Africa	**943**	**4**
Total	**12,674**	**1,793**

North American Natural Gas

Canadian Natural drilled a total of 777 natural gas wells as detailed below. For 2004, the revised natural gas program will be highlighted by expanded drilling programs in the Northwest Alberta and Northeast British Columbia core regions.

(number of wells)	2003 Actual	2004 Forecast
Northeast British Columbia	**78**	**172**
Northwest Alberta	**98**	**145**
North Alberta	**184**	**183**
South Alberta	**417**	**206**
Total	**777**	**706**

For 2004, Northeast British Columbia drilling reflects an increased Helmet drilling program, as well as a new shallow natural gas drilling program in the Fort St. John area, which benefits from the revised royalty regime for shallow natural gas wells in British Columbia.

North America Crude Oil and NGLs

Canadian Natural continues the disciplined development of its vast heavy crude oil prone land base. As has been previously articulated, these properties will be developed as heavy crude oil markets permit. Given the normal production profile of new heavy crude oil wells, fourth quarter production increases reflect the drilling program commenced during the second quarter. Canadian Natural's fourth quarter drilling program was concentrated on 71 primary heavy oil wells in North Alberta, for a total of 315 wells during the year.

As an integral part of the long-term heavy crude oil strategy mentioned above, the Company's Primrose drilling program continues with 41 new thermal wells having been drilled during 2003. With steaming having commenced in early 2004, first production from these new wells is expected in mid 2004. A further 17 wells will be drilled during the first quarter of 2004. Conventional production from the Pelican Lake field reflected no drilling activity during the second half of 2003. Canadian Natural views its 2003 Enhanced Oil Recovery waterflood test program as a success and as such, Canadian Natural will begin the phased roll out of the waterflood with approximately 20% of the field being under waterflood by the end of 2004. The waterflood will stabilize production, but will require a further 63 Pelican Lake productive wells to be converted from producer to water injectors and 43 new wells to be drilled as producers.

In February 2004, Canadian Natural announced the acquisition of heavy oil properties in its North Alberta core region for $467 million. The current production from the properties acquired by Canadian Natural is approximately 27,500 bbl/d of heavy oil and 9 mmcf/d of natural gas. The acquisition fits with Canadian Natural's strategy of dominating its core areas and related infrastructure with all of the properties acquired by the Company being located in its heavy oil core area. Canadian Natural expects to achieve operating cost reductions through synergies with its own existing facilities including additional throughput in its 100% owned ECHO pipeline. In addition, approximately 300 new well locations and over 400 well recompletion opportunities have been identified on these lands and will be added into project inventory.

The 2004 capital budget for North American crude oil and NGLs has been reduced by $65 million to $550 million, reflecting project deferrals implemented as part of the Petrovera acquisition. These project deferrals were comprised primarily of reduced heavy oil drilling. The revised 2004 drilling program consists of 110 conventional heavy oil wells, 51 thermal heavy oil wells, 43 light crude oil wells and 43 Pelican Lake oil wells.

North America Horizon Oil Sands Project

The 100% owned and operated Horizon Oil Sands Project is expected to be built in three phases and produce approximately 232 mbbl/d of light, sweet synthetic crude oil before royalties. The Company received the Joint Panel decision in January and Alberta Provincial Cabinet and EUB approvals in February. The third phase of engineering, EDS, will be substantially completed in 2004. In addition, the financing plan will be optimized and finalized coincident with the Board of Directors' sanction.

EDS, representing the detailed design of the project, progressed during the fourth quarter of 2003. Also during the fourth quarter, the Company completed construction of the major access road and related river spans that access the site. Clearing of trees is underway in order to facilitate drainage of the site and construction of deep underground facilities later this year.

The financing of the first phase of development will be guided by the principles of retaining as much direct ownership interest as possible while maintaining 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. The Company could also look to offload capital commitments through the acceptance of complementary business partners, or potentially, project joint venture partners. Recent commodity price increases have significantly strengthened the balance sheet of the Company, placing it in a better position to achieve all three of its guiding principles.

The 2004 capital budget for the Horizon Oil Sands Project will be phased in over 2004 dependent on regulatory approval and cost estimates. In 2004, the EDS will be completed with a capital budget of $150 million, and $50 million of pre-construction activities will be undertaken. If Federal Cabinet approval is received on a timely basis and Board of Directors approval is received based on acceptable certainty of forecasted capital costs, up to an additional $200 million of construction activities could be undertaken in 2004.

The Company currently employs 267 full time employees and 372 full time contractors on this project and expects this to continue to increase as the EDS continues. The members of this team are very experienced in all facets of oil sands construction and operations.

North Sea

Canadian Natural remains excited about prospects to create value from the crude oil platforms at Ninian and Murchison. During the fourth quarter, production at the Lyell Field, which produces through the Ninian Platform, was reduced in order to effect well workovers as well as to complete pipeline integrity checks prior to infill drilling programs scheduled for 2004. A natural gas compressor at the Murchison Field that is used to create gas lift to optimize liquids production was down, temporarily reducing production from that field.

During the fourth quarter, two producer wells and one injector well were drilled in the UK sector of the North Sea. Following Canadian Natural's drilling of an unsuccessful exploration well into the Permis Finistere Atlantique Block located offshore France, the Company has written off all related capital costs during the quarter as it has no current plans to continue exploration on the Block.

In 2004, Canadian Natural now anticipates drilling approximately 13 crude oil wells, implementing a secondary recovery natural gas injection scheme at Banff, optimizing Ninian and Murchison waterfloods, and continuing its successful 2003 recompletion program. The 2004 capital budget for the North Sea has been reduced by $40 million to $300 million reflecting project deferrals implemented as part of the Petrovera acquisition. As a result, average crude oil production is expected to remain relatively flat with current production levels; however, natural gas volumes will be lower as natural gas sales at Banff are diverted to reinjection.

Offshore West Africa

During the fourth quarter, Canadian Natural's 58.67% owned and operated Espoir development located offshore Côte d'Ivoire produced an average of 13.3 mbbl/d of light crude oil and 12 mmcf/d of natural gas. The waterflood program is now fully implemented and production has stabilized at the field.

At the 57.61% owned and operated Baobab Field, also located offshore Côte d'Ivoire, field development has commenced. 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. Crude oil production, which is expected to commence mid 2005 at gross well rates of approximately 45,000 bbl/d and subsequently peak at 60,000 bbl/d, will be sold directly from the FPSO, with the associated natural gas being transported to shore via the Espoir Field infrastructure. Development drilling commenced in early November and the FPSO is currently being fabricated in Singapore.

In Offshore Angola, drilling of the Zenza project was completed with no commercial quantities of hydrocarbons being encountered. 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 crude oil regions of the world. Canadian Natural will integrate new information gathered during the Zenza drill in order to select the best exploration drilling target, expected to be drilled in early 2005.

In 2004, the revised capital budget for Offshore West Africa was reduced by $60 million to $290 million. Canadian Natural anticipates $220 million to be spent on the ongoing development of the Baobab Field in Côte d'Ivoire. The remainder will be spent on the pre-development work for the West Espoir development.

FINANCIAL REVIEW

Canadian Natural is focused on maintaining a strong financial position in order to withstand volatile crude oil and natural gas commodity prices and the operational risks inherent in the crude oil and natural gas business environment.

During 2003, strong operational results and product pricing enabled the Company to repay approximately $0.7 billion of long-term debt. The strength of the Canadian dollar during the year also reduced carrying values of US dollar based borrowings by an additional $0.5 billion, resulting in a total decrease of long-term debt of $1.2 billion. Corporate debt to cash flow was reduced to 0.9 times versus 1.8 times at December 31, 2002, while debt to book capitalization improved to 32% from 46% at year end 2002. Corporate debt to EBITDA was reduced to 0.8 times versus 1.6 times at December 31, 2002.

During 2004, higher than budgeted prices received for the Company's products are expected to result in increased cash flow to the Company over the revised capital budget established in early 2004, after the acquisition of Petrovera. The Company will continue to allocate a minimum of 50% of its cash flow surplus toward debt repayment. The remaining excess will be directed to the Company's authorized share buy-back program and additional capital expenditures on conventional crude oil and natural gas opportunities. It is expected that the largest portion of any additional capital expenditures will take place in the fourth quarter of 2004 and accordingly will not add materially to Canadian Natural's 2004 average production volumes.

During 2003, 2.7 million common shares were purchased for cancellation under the Normal Course Issuer Bid for a total cost of $144 million, resulting in the Company ending the year with less outstanding common shares than it started the year.

Canadian Natural's Board of Directors has approved an increase in the annual dividend paid by the Company to $0.80 per common share from the previous level of $0.60 per common share. The 33% increase recognizes the stability of Canadian Natural's increased cash flow and provides a further return to shareholders. This is the fourth consecutive year in which the Company has paid dividends and the third consecutive year of increase in the distribution paid to its shareholders. The increased dividend will become effective with the quarterly payment of $0.20 per common share to be paid on April 1, 2004.

In order to increase the liquidity of its common shares, the Board of Directors will recommend to its shareholders to subdivide the Company's common shares on a 2 for 1 basis, which will result in an increase in the Company's total outstanding common shares to approximately 268 million common shares. This recommendation will be voted on by the shareholders at the Annual and Special Meeting of Shareholders meeting to be held on May 6, 2004.

YEAR-END RESERVES

Canadian Natural retains qualified independent petroleum engineering consultants, Sproule Associates Limited ("Sproule"), to evaluate 100% of the Company's proved and probable oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. Canadian Natural has been granted an exemption from the recently adopted National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101) which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Securities and Exchange Commission (SEC) requirements for certain disclosures required under NI 51-101. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose proved and probable reserves and future net revenues using forecast prices and costs. Canadian Natural has elected to disclose proved reserves using constant prices and costs as mandated by the SEC and has also provided proved and probable reserves under the same parameters as voluntary additional information. Another difference between the two standards is in the definition of proved reserves. As discussed in the Canadian Oil and Gas Evaluation Handbook (COGEH), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not be material.

The Board of Directors of the Company has a Reserves Committee, which has met with Sproule and carried out independent due diligence procedures with Sproule as to the Company's reserves.

RESERVES, NET OF ROYALTIES[1]

	December 31, 2003			
	Proved Developed[2]	Proved Undeveloped[2]	Proved Total[2]	Proved and Probable[3]
Crude Oil & NGLs (mmbbl)				
North America	**348**	**240**	**588**	**857**
North Sea	**138**	**84**	**222**	**317**
Offshore West Africa	**23**	**62**	**85**	**133**
	509	**386**	**895**	**1,307**
Natural Gas (bcf)				
North America	**2,140**	**286**	**2,426**	**2,919**
North Sea	**46**	**16**	**62**	**102**
Offshore West Africa	**12**	**52**	**64**	**72**
	2,198	**354**	**2,552**	**3,093**
Total Reserves (mmboe)	**875**	**445**	**1,320**	**1,823**
Reserve Replacement Ratio[4] (%)			**129%**	**308%**
Cost to Develop[5] ($/boe)				
10% discount	**0.24**	**4.02**	**1.51**	**1.60**
Present Value of Reserves[6] ($ million)				
10% discount	**13,079**	**3,037**	**16,116**	**20,164**

	December 31, 2002			
	Proved Developed[7]	Proved Undeveloped[7]	Proved Total[7]	Proved and Probable[7]
Crude Oil & NGLs (mmbbl)				
North America	340	231	571	636
North Sea	107	95	202	277
Offshore West Africa	27	48	75	121
	474	374	848	1,034
Natural Gas (bcf)				
North America	2,185	261	2,446	2,765
North Sea	57	14	71	89
Offshore West Africa	27	44	71	90
	2,269	319	2,588	2,944
Total Reserves (mmboe)	852	427	1,279	1,525
Reserve Replacement Ratio[4] (%)			245%	275%
Cost to Develop[5] ($/boe)				
10% discount	0.42	3.85	1.57	1.53
Present Value of Reserves[6] ($ million)				
10% discount	15,485	3,850	19,335	20,965

CRUDE OIL AND NGLs RESERVES RECONCILIATION[1] (mmbbl, net of royalties)

	North America	North Sea	Offshore West Africa	Total
Proved Reserves				
Reserves, December 31, 2001	583	78	60	721
Extensions & discoveries	26	1	14	41
Property purchases	44	114	-	158
Property disposals	(1)	(18)	-	(19)
Production	(55)	(13)	(2)	(70)
Revisions of prior estimates	(26)	40	3	17
Reserves, December 31, 2002	571	202	75	848
Extensions & discoveries	**1**	**-**	**13**	**14**
Infill drilling	**54**	**-**	**-**	**54**
Improved recovery	**9**	**-**	**-**	**9**
Property purchases	**7**	**27**	**-**	**34**
Property disposals	**-**	**-**	**-**	**-**
Production	**(56)**	**(21)**	**(4)**	**(81)**
Revisions of prior estimates	**2**	**14**	**1**	**17**
Reserves, December 31, 2003	**588**	**222**	**85**	**895**
Proved and Probable Reserves				
Reserves, December 31, 2001	**670**	**100**	**103**	**873**
Extensions & discoveries	26	-	5	31
Property purchases	52	138	-	190
Property disposals	(1)	(22)	-	(23)
Production	(55)	(13)	(2)	(70)
Revisions of prior estimates	(56)	74	15	33
Reserves, December 31, 2002	**636**	**277**	**121**	**1,034**
Extensions & discoveries	**1**	**-**	**17**	**18**
Infill drilling	**58**	**-**	**-**	**58**
Improved recovery	**25**	**-**	**12**	**37**
Property purchases	**10**	**33**	**-**	**43**
Property disposals	**-**	**-**	**-**	**-**
Production	**(56)**	**(21)**	**(4)**	**(81)**
Revisions of prior estimates	**183**	**28**	**(13)**	**198**
Reserves, December 31, 2003	**857**	**317**	**133**	**1,307**

NATURAL GAS RESERVES RECONCILIATION[1] (bcf, net of royalties)

Proved Reserves	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2001	**2,064**	**94**	**67**	**2,225**
Extensions & discoveries	106	-	4	110
Property purchases	699	18	-	717
Property disposals	(3)	(56)	-	(59)
Production	(346)	(10)	(1)	(357)
Revisions of prior estimates	(74)	25	1	(48)
Reserves, December 31, 2002	**2,446**	**71**	**71**	**2,588**
Extensions & discoveries	**58**	**-**	**6**	**64**
Infill drilling	**243**	**-**	**-**	**243**
Improved recovery	**8**	**-**	**-**	**8**
Property purchases	**50**	**19**	**-**	**69**
Property disposals	**(3)**	**-**	**-**	**(3)**
Production	**(355)**	**(17)**	**(3)**	**(375)**
Revisions of prior estimates	**(21)**	**(11)**	**(10)**	**(42)**
Reserves, December 31, 2003	**2,426**	**62**	**64**	**2,552**

Proved and Probable Reserves	North America	North Sea	Offshore West Africa	Total
Reserves, December 31, 2001	**2,344**	**118**	**88**	**2,550**
Extensions & discoveries	112	-	(7)	105
Property purchases	764	24	-	788
Property disposals	(3)	(62)	-	(65)
Production	(346)	(10)	(1)	(357)
Revisions of prior estimates	(106)	19	10	(77)
Reserves, December 31, 2002	**2,765**	**89**	**90**	**2,944**
Extensions & discoveries	**72**	**-**	**11**	**83**
Infill drilling	**285**	**-**	**-**	**285**
Improved recovery	**26**	**-**	**(6)**	**20**
Property purchases	**59**	**22**	**-**	**81**
Property disposals	**(3)**	**-**	**-**	**(3)**
Production	**(355)**	**(17)**	**(3)**	**(375)**
Revisions of prior estimates	**70**	**8**	**(20)**	**58**
Reserves, December 31, 2003	**2,919**	**102**	**72**	**3,093**

The following information for reserves before royalties is provided for comparative purposes:

RESERVES, BEFORE ROYALTIES[(1)]

	December 31, 2003			
	Proved Developed[(2)]	**Proved Undeveloped[(2)]**	**Proved Total[(2)]**	**Proved and Probable[(3)]**
Crude Oil & NGLs (mmbbl)	**568**	**432**	**1,000**	**1,481**
Natural Gas (bcf)	**2,725**	**429**	**3,154**	**3,823**
Total Reserves (mmboe)	**1,022**	**504**	**1,526**	**2,118**

	December 31, 2002			
	Proved Developed[(7)]	Proved Undeveloped[(7)]	Proved Total[(7)]	Proved and Probable[(7)]
Crude Oil & NGLs (mmbbl)	535	426	961	1,181
Natural Gas (bcf)	2,811	398	3,209	3,659
Total Reserves (mmboe)	1,004	492	1,496	1,791

FINDING AND ONSTREAM COSTS

	2003	2002	2001	Three Year Total
Net Reserve Replacement Expenditures ($ million)	**2,283**	3,928	1,745	7,956
Reserve Additions[(8)] (mmboe, net of royalties)				
Proved	**185**	317	172	674
Proved and Probable	**441**	356	206	1,003
Finding and On Stream Costs Per BOE[(9)] (net of royalties)				
Proved	**12.34**	12.39	10.15	11.80
Proved and Probable	**5.18**	11.03	8.47	7.93

[(1)]Reserve estimates and present value calculations are based upon constant reference price assumptions as detailed below.

Crude Oil & NGLs	*Company Average Price ($C/bbl)*	*WTI @ Cushing Oklahoma ($US/bbl)*	*Hardisty Heavy 12˚ API ($C/bbl)*	*North Sea Brent ($US/bbl)*
December 31, 2003	*32.02*	*32.56*	*26.16*	*30.14*
December 31, 2002	*39.23*	*31.23*	*35.04*	*30.21*

Natural Gas	*Company Average Price ($C/mcf)*	*Henry Hub Louisiana ($US/mcf)*	*Alberta AECO C ($C/mcf)*	*British Columbia Huntingdon Sumas ($C/bbl)*
December 31, 2003	*6.63*	*5.80*	*6.88*	*6.94*
December 31, 2002	*5.88*	*4.59*	*5.97*	*6.53*

A foreign exchange rate of $US 0.77/$C 1.00 was used in the 2003 evaluation. A foreign exchange rate of $US 0.63/$C 1.00 was used in the 2002 evaluation.

[2] 2003 proved reserve estimates and values were evaluated in accordance with the Securities and Exchange Commission (SEC) requirements. The stated reserves have a reasonable certainty of being economically recoverable using year-end prices and costs held constant throughout the productive life of the properties.

[3] 2003 proved and probable reserve estimates and values were evaluated in accordance with the standards of the Canadian Oil and Gas Evaluation Handbook ("COGEH") and as mandated by NI 51-101. The stated reserves have a 50% probability of equaling or exceeding the indicated quantities and were evaluated using year-end costs and prices held constant throughout the productive life of the properties.

[4] Reserve replacement ratios were calculated using annual net reserve additions comprised of all change categories divided by the net production for that year.

[5] Cost to develop represents total future capital for each reserves category excluding abandonment capital divided by the reserves associated with that category.

[6] Present value of reserves are based upon discounted cash flows associated with prices and operating expenses held constant into the future, before income taxes. Only future development costs and abandonment costs have been applied against future net revenues.

[7] 2002 reserve estimates were evaluated in accordance with the standards of National Policy 2-B which has now been replaced by NI 51-101. The stated reserves were reasonably evaluated as economically productive using year-end costs and prices held constant throughout the productive life of the properties.

[8] Reserves additions are comprised of all categories of reserves changes, exclusive of production.

[9] Reserves finding and on stream costs are determined by dividing total capital costs for each year excluding cost associated with head office, abandonments, midstream and Project Horizon by reserves additions for that year.

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 year ended December 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 derivative financial instruments, except where noted otherwise.

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

		Three Months Ended			Year Ended	
		Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Revenue[1]		**$ 1,368**	$ 1,434	$ 1,397	**$ 5,972**	$ 4,342
Cash flow from operations attributable to common shareholders[2]		**$ 734**	$ 758	$ 777	**$ 3,160**	$ 2,254
Per common share	– basic	**$ 5.48**	$ 5.62	$ 5.81	**$ 23.54**	$ 17.63
	– diluted	**$ 5.42**	$ 5.56	$ 5.62	**$ 23.06**	$ 16.99
Net earnings attributable to common shareholders[3]		**$ 251**	$ 203	$ 209	**$ 1,407**	$ 570
Per common share	– basic	**$ 1.87**	$ 1.51	$ 1.56	**$ 10.48**	$ 4.46
	– diluted	**$ 1.83**	$ 1.49	$ 1.51	**$ 10.14**	$ 4.31
Business combination		**$ -**	$ -	$ -	**$ -**	$ 2,393
Capital expenditures, net of dispositions		**$ 662**	$ 621	$ 292	**$ 2,506**	$ 1,676

[1] *Restated to exclude transportation costs from revenue.*

[2] *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.*

	Three Months Ended			*Year Ended*	
($ millions)	***Dec 31 2003***	*Sep 30 2003*	*Dec 31 2002*	***Dec 31 2003***	*Dec 31 2002*
Net earnings attributable to common shareholders	***$ 251***	*$ 203*	*$ 209*	***$ 1,407***	*$ 570*
Non-cash items:					
Future tax on dividend on preferred securities	***(1)***	*(1)*	*(1)*	***(4)***	*(4)*
Revaluation of preferred securities, net of tax	***(4)***	*-*	*(1)*	***(18)***	*(1)*
Stock-based compensation expense	***63***	*32*	*-*	***200***	*-*
Depletion, depreciation and amortization	***405***	*401*	*386*	***1,565***	*1,314*
Unrealized foreign exchange gain	***(81)***	*(11)*	*-*	***(320)***	*(35)*
Deferred petroleum revenue (recovery) tax	***(17)***	*1*	*6*	***(9)***	*10*
Future income tax expense	***118***	*133*	*178*	***339***	*400*
Cash flow from operations attributable to common shareholders	***$ 734***	*$ 758*	*$ 777*	***$ 3,160***	*$ 2,254*

[3] *After dividend and revaluation of preferred securities.*

Net earnings and cash flow from operations reached record levels in 2003. Net earnings increased 147% to $1,407 million and 20% to $251 million for the year and three months ended December 31, 2003 from the comparable periods in 2002. Cash flow increased 40% to $3,160 million for the year ended December 31, 2003, but decreased 6% to $734 million for the three months ended December 31, 2003 from the comparable periods in 2002. The increase in net earnings and cash flow for the year ended December 31, 2003 was a result of higher product prices for crude oil, NGLs and natural gas and increased production volumes. The increase in production volumes was primarily associated with an active capital expenditure program, the consolidation of working interests in the North Sea, and the impact of a full year of results relating to the acquisition of Rio Alto Exploration Ltd. ("Rio Alto") on July 1, 2002. Net earnings for 2003 were impacted compared to the prior year due to the reduction in the Canadian federal and Alberta provincial corporate income tax rates, the strengthening Canadian dollar resulting in an unrealized foreign exchange gain on the Company's US dollar denominated debt, and the recognition of stock-based compensation expense associated with the Company's Stock Option Plan. Net earnings increased in the fourth quarter of 2003 from the prior year due to the strengthening Canadian dollar, resulting in higher unrealized foreign exchange gains. Cash flow in the fourth quarter of 2003 decreased from the prior quarter due to decreased natural gas production and higher Petroleum Revenue Tax ("PRT") in the North Sea.

OPERATING HIGHLIGHTS

	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Crude oil and NGLs ($/bbl, except daily production)					
Daily production (bbl/d)	**244,262**	247,016	240,596	**242,392**	215,335
Sales price[1]	**$ 30.02**	$ 30.97	$ 31.10	**$ 31.59**	$ 29.76
Royalties	**2.22**	2.56	3.53	**2.77**	3.16
Production expense	**9.45**	10.14	9.10	**10.28**	8.45
Netback	**$ 18.35**	$ 18.27	$ 18.47	**$ 18.54**	$ 18.15
Natural gas ($/mcf, except daily production)					
Daily production (mmcf/d)	**1,270**	1,289	1,365	**1,299**	1,232
Sales price[1]	**$ 5.23**	$ 5.50	$ 5.00	**$ 6.02**	$ 3.76
Royalties	**1.05**	1.11	1.09	**1.32**	0.78
Production expense	**0.63**	0.63	0.57	**0.60**	0.57
Netback	**$ 3.55**	$ 3.76	$ 3.34	**$ 4.10**	$ 2.41
Barrels of oil equivalent ($/boe, except daily production)					
Daily production (boe/d)	**455,935**	461,882	468,132	**458,814**	420,722
Sales price[1]	**$ 30.64**	$ 31.94	$ 30.54	**$ 33.75**	$ 26.25
Royalties	**4.12**	4.46	4.98	**5.20**	3.91
Production expense	**6.81**	7.17	6.34	**7.15**	5.99
Netback	**$ 19.71**	$ 20.31	$ 19.22	**$ 21.40**	$ 16.35

(1) Includes financial instruments and transportation costs.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
WTI benchmark price (US $/bbl)	**$ 31.18**	$ 30.20	$ 28.17	**$ 31.02**	$ 26.11
Differential to LLB blend (US $/bbl)	**$ 10.39**	$ 8.72	$ 8.13	**$ 8.55**	$ 6.50
Condensate benchmark price (US $/bbl)	**$ 31.57**	$ 29.97	$ 28.56	**$ 31.42**	$ 26.00
NYMEX benchmark price (US $/mmbtu)	**$ 4.58**	$ 5.10	$ 3.99	**$ 5.44**	$ 3.25
AECO benchmark price (C $/GJ)	**$ 5.30**	$ 5.95	$ 4.98	**$ 6.35**	$ 3.86
US/Canadian dollar average exchange rate (US $)	**0.76**	0.72	0.64	**0.71**	0.64

World crude oil prices remained strong throughout 2003 due to concerns over supply relating to the war in Iraq, the strike in Venezuela, the unrest in Nigeria and rising worldwide demand. West Texas Intermediate ("WTI") prices averaged US $31.02 per bbl for the year ended December 31, 2003, up 19% from US $26.11 per bbl in 2002. WTI averaged US $31.18 per bbl in the fourth quarter of 2003, up 3% compared to US $30.20 per bbl in the prior quarter, and up 11% from US $28.17 per bbl compared to the fourth quarter of 2002. WTI prices continued to remain strong in the fourth quarter.

Natural gas prices increased in 2003. AECO natural gas price increased 65% to average $6.35 per GJ in 2003 compared to $3.86 per GJ in 2002. NYMEX natural gas spot price increased 67% to average US $5.44 per mmbtu compared to US $3.25 per mmbtu in 2002. Natural gas prices decreased in the fourth quarter of 2003 to their lowest levels of the year. AECO natural gas price averaged $5.30 per GJ in the fourth quarter of 2003, down 11% compared to $5.95 per GJ in the prior quarter, but up 6% compared to the fourth quarter of 2002. NYMEX natural gas spot price averaged US $4.58 per mmbtu in the fourth quarter of 2003, down 10% compared to US $5.10 per mmbtu in the prior quarter, but up 15% compared to the fourth quarter of 2002. The decrease in natural gas prices in the fourth quarter of 2003 was due to reduced demand and the increase in natural gas storage levels.

PRODUCT PRICES

	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 25.86**	$ 27.48	$ 27.57	**$ 27.77**	$ 27.04
North Sea	**$ 41.93**	$ 39.84	$ 41.83	**$ 42.43**	$ 39.79
Offshore West Africa	**$ 36.42**	$ 37.37	$ 43.15	**$ 36.47**	$ 40.10
Company average	**$ 30.02**	$ 30.97	$ 31.10	**$ 31.59**	$ 29.76
Natural gas ($/mcf) [(1)]					
North America	**$ 5.32**	$ 5.62	$ 5.04	**$ 6.14**	$ 3.78
North Sea	**$ 3.32**	$ 2.57	$ 3.20	**$ 3.03**	$ 2.75
Offshore West Africa	**$ 3.95**	$ 4.59	$ 4.63	**$ 4.37**	$ 4.82
Company average	**$ 5.23**	$ 5.50	$ 5.00	**$ 6.02**	$ 3.76
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**52%**	52%	52%	**49%**	58%
Natural gas	**48%**	48%	48%	**51%**	42%

(1) Including financial instruments and transportation costs.

Realized crude oil prices increased for the year ended December 31, 2003 from the comparable period in 2002 due to higher world crude oil prices. Overall, realized crude oil prices decreased for the three months ended December 31, 2003 from the comparable period in 2002 due to the stronger Canadian dollar and higher heavy oil differentials in North America. Heavy oil differentials averaged US $10.39 per bbl in the fourth quarter of 2003, up 28% from US $8.13 per bbl in the fourth quarter of 2002 and up 19% from US $8.72 per bbl in the third quarter of 2003. The realized crude oil price in the North Sea increased in the fourth quarter as a result of higher world oil prices and the impact of the Company's derivative financial instruments. The Offshore West Africa realized crude oil price decreased due to the timing of and prices received on specific product lifting dates. As a result of the use of derivative financial instruments, the realized price from the sale of crude oil decreased $1.07 per bbl for the year ended December 31, 2003 (2002 - $1.46 per bbl reduction). The use of derivative financial instruments increased the Company's price of crude oil by $0.55 per bbl for the fourth quarter of 2003 ($0.48 per bbl and $1.73 per bbl reduction, respectively, for the quarters ended September 30, 2003 and December 31, 2002).

The Company continues to look for opportunities to expand its heavy oil markets. In particular, the Company is testing a 50/50 blend of bitumen and synthetic crude oil called "Synbit". Synbit has similar properties to medium sour crude and is expected to decrease the demand for supplies of condensate currently blended with bitumen. The Company is currently marketing 34,000 bbl/d of Synbit to refiners located in the U.S. Midwest and plans to expand this effort throughout 2004 to build a solid new market for both heavy and synthetic crude oil.

The Company's average natural gas price increased 60% to $6.02 per mcf for the year ended December 31, 2003 and increased 5% to $5.23 per mcf for the three months ended December 31, 2003 from the comparable periods in 2002 due to market forces of supply and demand. The Company's average natural gas price decreased 5% in the fourth quarter from the prior quarter due to higher than expected storage levels heading into the winter heating season. Derivative financial instruments entered into by the Company on its natural gas portfolio decreased the price received by $0.19 per mcf for the year 2003 and $0.03 per mcf for the fourth quarter of 2003 ($0.01 per mcf reduction for the year ended December 31, 2002 and a $0.07 per mcf reduction for the quarters ended September 30, 2003 and December 31, 2002).

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

	Q4 2003	Q3 2003	Q4 2002
Canadian Natural's Wellhead Price[1]			
Light crude oil and NGLs (C $/bbl)	**$ 34.76**	$ 34.37	$ 36.08
Pelican Lake crude oil (C $/bbl)	**$ 24.74**	$ 27.20	$ 25.30
Primary heavy crude oil (C $/bbl)	**$ 22.18**	$ 24.93	$ 24.78
Thermal heavy crude oil (C $/bbl)	**$ 22.05**	$ 23.58	$ 24.11
Natural gas (C $/mcf)	**$ 5.32**	$ 5.62	$ 5.04

[1] *Including financial instruments and transportation costs.*

DAILY PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Crude oil and NGLs (bbl/d)					
North America	**176,429**	174,838	181,744	**174,895**	169,675
North Sea	**54,529**	60,193	51,478	**56,869**	38,876
Offshore West Africa	**13,304**	11,985	7,374	**10,628**	6,784
Total	**244,262**	247,016	240,596	**242,392**	215,335
Natural gas (mmcf/d)					
North America	**1,206**	1,229	1,331	**1,245**	1,204
North Sea	**52**	49	32	**46**	27
Offshore West Africa	**12**	11	2	**8**	1
Total	**1,270**	1,289	1,365	**1,299**	1,232
Product mix					
Light crude oil and NGLs	**25%**	26%	22%	**25%**	21%
Pelican Lake crude oil	**5%**	5%	6%	**5%**	7%
Primary heavy crude oil	**16%**	15%	15%	**15%**	14%
Thermal heavy crude oil	**8%**	8%	8%	**8%**	9%
Natural gas	**46%**	46%	49%	**47%**	49%

Crude oil and NGLs production for the year and three months ended December 31, 2003 increased 13% or 27,057 bbl/d and 2% or 3,666 bbl/d respectively from the comparable periods in 2002. Crude oil and NGLs production for the fourth quarter of 2003 was in line with the Company's guidance previously provided.

Crude oil and NGLs production in North America for the year ended December 31, 2003 increased 3% or 5,220 bbl/d from the comparable period in 2002. The increase was due to additional heavy crude oil drilling activity in the second quarter of 2003, property acquisitions in the Company's core operating regions in 2002, and the acquisition of Rio Alto. Crude oil and NGLs production in North America for the three months ended December 31, 2003 decreased 3% or 5,315 bbl/d from the comparable period in 2002 but increased 1% or 1,591 bbl/d from the prior quarter. The decrease in North American crude oil production for the three months ended December 31, 2003 from the comparable period in 2002 was due to an increased focus on natural gas drilling and production declines at the Pelican Lake Field. The production declines in Pelican Lake were the result of the implementation of the water flood program that required producing wells to be converted to injectors.

Crude oil production from the North Sea for the year and three months ended December 31, 2003 increased 46% or 17,993 bbl/d and 6% or 3,051 bbl/d 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 last two years. Crude oil production in the fourth quarter decreased 9% or 5,664 bbl/d from the previous quarter due to the timing of well workovers, which resulted in the Lyell Field and the Columba 2B well being shut in for portions of the fourth quarter.

Offshore West Africa crude oil production for the year and three months ended December 31, 2003 increased 57% or 3,844 bbl/d and 80% or 5,930 bbl/d from the comparable periods in 2002. In addition, crude oil production in the fourth quarter increased 11% or 1,319 bbl/d from the prior quarter. The increases in production are due to the perforation of the upper zone of the East Espoir structure in the second quarter of 2003 and the completion of the fourth water injection well and an additional production well in the third quarter of 2003.

Natural gas production for the year and fourth quarter of 2003 was in line with the Company's guidance previously provided. Natural gas production for the year ended December 31, 2003 increased 5% or 67 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 in the fourth quarter continued to represent the Company's largest product offering but decreased 7% or 95 mmcf/d from the comparable period in 2002. The decrease was due to drilling activity in the last half of 2003, which focused on shallow natural gas in the South Alberta region, not offsetting the normal production declines from winter access fields in the Company's other core regions. Natural gas production decreased 1% or 19 mmcf/d from the prior quarter due to normal production declines. Production from the Ladyfern field in Northeast British Columbia declined 8 mmcf/d to average 39 mmcf/d during the fourth quarter of 2003, down from 47 mmcf/d in the third quarter of 2003 and 127 mmcf/d in the fourth quarter of 2002 as well pressures continue to decline. Fourth quarter production was also impacted by the shut in of approximately 11 mmcf/d of the Company's natural gas production in the Athabasca Wabiskaw-McMurray oilsands area pursuant to the decision of the Alberta Energy and Utilities Board ("EUB") effective September 1, 2003. Based on the EUB Regional Geological Study, 5 mmcf/d of natural gas previously shut in was brought back on production in 2004 and the Company estimates that an additional 11 mmcf/d of natural gas production may be at risk of being shut in. No shut-in date has been established on the additional 11 mmcf/d of natural gas. The Alberta Department of Energy ("ADOE") has announced an interim assistance plan under which Alberta crown royalty deferrals are granted at a rate of $0.60/mcf of shut-in production.

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.

Natural gas production in Offshore West Africa increased over the comparable period in the prior year due to the start up of the natural gas pipeline in the third quarter of 2002. Natural gas production also increased over the comparable periods in the prior year due to the perforation of the upper zone of the East Espoir structure in the second quarter of 2003 and the drilling of an additional production well in the third quarter of 2003.

The Company expects first quarter production levels to average 1,285 to 1,315 mmcf/d of natural gas and 245,000 to 265,000 bbl/d of crude oil and NGLs. Revised annual production levels of approximately 1,320 to 1,395 mmcf/d of natural gas and 263,000 to 283,000 bbl/d of crude oil and NGLs are expected in 2004.

ROYALTIES

	Three Months Ended						Year Ended			
		Dec 31 2003		Sep 30 2003		Dec 31 2002		**Dec 31 2003**		Dec 31 2002
Crude oil and NGLs ($/bbl)										
North America	**$**	**3.05**	$	3.52	$	3.82	**$**	**3.79**	$	3.42
North Sea	**$**	**(0.15)**	$	0.09	$	2.79	**$**	**(0.03)**	$	2.30
Offshore West Africa	**$**	**1.03**	$	1.13	$	1.35	**$**	**1.08**	$	1.35
Company average	**$**	**2.22**	$	2.56	$	3.53	**$**	**2.77**	$	3.16
Natural gas ($/mcf)										
North America	**$**	**1.10**	$	1.16	$	1.11	**$**	**1.38**	$	0.80
Offshore West Africa	**$**	**0.11**	$	0.14	$	0.15	**$**	**0.13**	$	0.15
Company average	**$**	**1.05**	$	1.11	$	1.09	**$**	**1.32**	$	0.78
Company average ($/boe)	**$**	**4.12**	$	4.46	$	4.98	**$**	**5.20**	$	3.91
Percentage of revenue[(1) (2)]										
Crude oil and NGLs		**8%**		8%		11%		**9%**		10%
Natural gas		**20%**		20%		21%		**21%**		21%
Boe		**14%**		14%		16%		**15%**		14%

(1) Excludes the impact of financial instruments.
(2) Transportation costs netted against revenue.

North America crude oil and NGLs royalties for the year ended December 31, 2003 increased on a per barrel basis from the comparable period in the prior year due to higher crude oil prices and certain heavy oil projects reaching payout in 2002 and becoming subject to higher government royalty rates. North America crude oil and NGLs royalties for the three months ended December 31, 2003 decreased on a per barrel basis from the comparable period in 2002 and the prior quarter due to lower realized wellhead 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 fourth quarter of 2003, the Company received a refund of royalties previously provided related to the Ninian Field.

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

PRODUCTION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Crude oil and NGLs ($/bbl)					
North America	**$ 8.43**	$ 9.27	$ 7.34	**$ 9.14**	$ 6.73
North Sea	**$ 13.42**	$ 13.25	$ 14.68	**$ 14.07**	$ 15.06
Offshore West Africa	**$ 6.67**	$ 7.11	$ 13.68	**$ 8.68**	$ 13.63
Company average	**$ 9.45**	$ 10.14	$ 9.10	**$ 10.28**	$ 8.45
Natural gas ($/mcf)					
North America	**$ 0.60**	$ 0.58	$ 0.55	**$ 0.57**	$ 0.55
North Sea	**$ 1.16**	$ 1.60	$ 1.25	**$ 1.33**	$ 1.53
Offshore West Africa	**$ 1.18**	$ 1.24	$ 1.85	**$ 1.39**	$ 1.81
Company average	**$ 0.63**	$ 0.63	$ 0.57	**$ 0.60**	$ 0.57
Company average ($/boe)	**$ 6.81**	$ 7.17	$ 6.34	**$ 7.15**	$ 5.99

North America crude oil and NGLs production expense per barrel increased for the year and three months ended December 31, 2003 from the comparable periods in 2002. The increase was due to the impact of higher natural gas prices on the costs of fuel gas used in the generation of steam in the Company's thermal heavy oil operations, as well as slightly higher steam oil ratios. Conversely, fourth quarter 2003 production expense per barrel decreased from the third quarter 2003 due to a reduction in natural gas prices and as a result of cost reductions achieved on light and heavy oil properties acquired in 2002. Production expense per barrel also decreased as a result of reduced heavy oil activity in the last half of 2003. The decrease in production expense per barrel was partially offset by higher unit costs associated with Pelican Lake, which have increased from historical levels due to the conversion of producing wells to injection wells during the implementation of the waterflood pilot project.

North Sea crude oil production expense varies on a per barrel basis from both the comparable periods in the prior year and the prior quarter is a result of the timing of maintenance work and the changes in production volumes on a relatively fixed cost base.

Offshore West Africa crude oil production expenses 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 per mcf in the year and three months ended December 31, 2003 increased marginally from the comparable periods in the prior year as a result of a general increase in service costs associated with increased industry activity. North Sea natural gas production expense decreased per mcf 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 production expense decreased per mcf for the year and three months ended December 31, 2003 as production volumes increased while costs remained relatively fixed.

MIDSTREAM ($ millions)

	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Revenue	**$ 16**	$ 13	$ 15	**$ 61**	$ 52
Operating costs	**4**	3	5	**15**	14
Operating cash flow	**12**	10	10	**46**	38
Depreciation	**1**	2	2	**7**	8
Segment earnings before taxes	**$ 11**	$ 8	$ 8	**$ 39**	$ 30

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 86% of the Company's heavy oil production was transported to international 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 for the year ended December 31, 2003 from the comparable period in 2002 due to higher electricity prices received in the first quarter of 2003 and increased revenue generated as a result of the expansion of the ECHO pipeline. The expansion of the ECHO pipeline was completed in October 2003 and increased capacity to 72 mbbl/d from 58 mbbl/d. Midstream revenue increased for the three months ended December 31, 2003 from the prior quarter due to the expansion of the Echo pipeline and the cogeneration plant returning to full operations after being down for maintenance during the third quarter.

The Cold Lake Pipeline Limited Partnership, in which the Company has a 15% working interest, will be investing $16 million in 2004 to construct new facilities to allow shipment of up to 60,000 bbl/d of the Synbit product. Currently, the Cold Lake pipeline transports a single oil blend consisting of heavy Cold Lake bitumen and light conventional condensate. The new SynBit blend stream will include light synthetic oil as a blending component to dilute the heavy, tar-like, Cold Lake bitumen. The SynBit project will involve construction of two 80,000 barrel storage tanks, pumping facilities and metering equipment on the Cold Lake system. Regulatory approvals have been obtained and construction activity is currently underway.

DEPLETION, DEPRECIATION AND AMORTIZATION

	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Expense ($ millions)	**$ 404**	$ 399	$ 384	**$ 1,558**	$ 1,306
$/boe	**$ 9.59**	$ 9.41	$ 8.92	**$ 9.30**	$ 8.51

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

DD&A for the year and three months ended December 31, 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. In addition, DD&A included the write-off of $12 million of costs associated with the Company's exploration activity in offshore France. DD&A increased from the prior quarter in total and per boe due to higher finding and development costs.

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Net expense ($ millions)	**$ 24**	$ 22	$ 17	**$ 87**	$ 61
$/boe	**$ 0.58**	$ 0.51	$ 0.41	**$ 0.52**	$ 0.40

Administration expense for the year and three months ended December 31, 2003 increased in total and on a per boe basis from the comparable periods in 2002 due to higher staffing levels associated with the growth in the Company's expanding asset base.

STOCK-BASED COMPENSATION

	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Expense ($ millions)	**$ 63**	$ 32	$ -	**$ 200**	$ -
$/boe	**$ 1.50**	$ 0.77	$ -	**$ 1.20**	$ -

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 surrendered. The amendment to the Option Plan balances the need for a long-term compensation program to retain employees with reducing the impact of dilution on current shareholders and the reporting of the expense associated with stock options. Transparency of the cost of the Option Plan is increased since changes in the intrinsic value of outstanding stock options are expensed. 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 $171 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 year to date is $200 million ($136 million after tax). The liability is 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. For the period ended December 31, 2003, the Company has paid $31 million for stock options surrendered for cash settlement.

INTEREST EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Interest expense ($ millions)	**$ 33**	$ 35	$ 53	**$ 157**	$ 159
$/boe	**$ 0.79**	$ 0.83	$ 1.22	**$ 0.94**	$ 1.03
Average effective interest rate	**4.5%**	4.5%	5.0%	**4.7%**	4.5%

Interest expense for the year and three months ended December 31, 2003 decreased from the comparable periods as a result of lower debt levels as the Company used excess cash flow generated to repay $740 million of long-term debt in 2003. 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			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Realized foreign exchange (gain) loss	**$ (6)**	$ 3	$ 2	**$ 8**	$ 4
Unrealized foreign exchange (gain)	**(81)**	(11)	-	**(320)**	(35)
Total	**$ (87)**	$ (8)	$ 2	**$ (312)**	$ (31)

The Canadian dollar increased to US $0.77 at December 31, 2003 compared to US $0.63 at January 1, 2003, 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. 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.

TAXES ($ millions, except income tax rates)

	Three Months Ended			Year Ended	
Taxes other than income tax	**Dec 31 2003**	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Current	**$ 43**	$ 28	$ 15	**$ 116**	$ 53
Deferred	**(17)**	1	6	**(9)**	10
Total	**$ 26**	$ 29	$ 21	**$ 107**	$ 63
Current income tax					
North Sea	**$ 2**	$ 5	$ (35)	**$ 23**	$ (19)
Offshore West Africa	**3**	3	1	**10**	6
North America – Current income tax	**3**	12	-	**43**	-
North America – Large corporations tax	**1**	5	6	**16**	21
Total	**$ 9**	$ 25	$ (28)	**$ 92**	$ 8
Future income tax	**$ 118**	$ 133	$ 178	**$ 339**	$ 400
Effective income tax rate	**33.9%**	43.6%	41.7%	**23.6%**	41.6%

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 crude oil prices and increased production levels. Fourth quarter taxes other than income taxes increased from the previous quarter due to higher realized crude oil prices in the North Sea.

North Sea current income tax for the year and three months ended December 31, 2003 increased from the previous year due to the changes in the tax rules in the North Sea. In 2003, a supplementary charge of 10% on profits from UK North Sea crude oil and natural gas production was introduced. 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. In addition, the first year capital allowance rate for plant and machinery expenditures was increased to 100% from the previous rate of 25%. In the fourth quarter of 2002, North Sea current income tax expense was positively impacted by the settlement of certain outstanding matters from prior years in the amount of $11 million. Current income tax in the fourth quarter 2003 decreased from the third quarter due to higher PRT expense, which is deductible against corporate income taxes.

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 2003, the Canadian Federal Government passed legislation to eliminate the federal Large Corporations Tax ("LCT") over a five-year period starting January 1, 2004. The LCT was levied at a rate of 0.225% of the Company's taxable capital employed in Canada in 2003 (2004 – 0.2%). The Federal Government also passed 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 provides 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, the future income tax liability in North America was decreased by $247 million in 2003. In addition, in 2003 the North America future tax liability was reduced by $31 million as a result of a reduction in the Alberta corporate income tax rate (2002 - $21 million).

CAPITAL EXPENDITURES ($ millions)	Three Months Ended			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Business combinations	**$ -**	$ -	$ -	**$ -**	$ 2,393
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 29**	$ 106	$ 39	**$ 336**	$ 440
Land acquisition and retention	**44**	53	18	**154**	114
Seismic evaluations	**25**	12	19	**77**	63
Well drilling, completion and equipping	**352**	256	139	**1,194**	626
Pipeline and production facilities	**133**	133	45	**522**	292
Total net reserve replacement expenditures	**583**	560	260	**2,283**	1,535
Horizon Oil Sands Project	**52**	32	19	**152**	68
Midstream	**2**	5	6	**11**	20
Abandonments	**20**	14	4	**40**	43
Head office	**5**	10	3	**20**	10
Total net capital expenditures	**$ 662**	$ 621	$ 292	**$ 2,506**	$ 1,676
North America	**$ 431**	$ 407	$ 124	**$ 1,769**	$ 1,026
North Sea	**106**	99	120	**338**	323
Offshore West Africa	**46**	54	16	**176**	186
Horizon Oil Sands Project	**52**	32	19	**152**	68
Midstream	**2**	5	6	**11**	20
Abandonments	**20**	14	4	**40**	43
Head office	**5**	10	3	**20**	10
Total net capital expenditures	**$ 662**	$ 621	$ 292	**$ 2,506**	$ 1,676

In 2003, the Company drilled a total of 777 net natural gas wells and 458 net crude oil wells, a 380% and a 73% increase respectively over the comparable period in 2002. North America fourth quarter drilling was focused in the Company's heavy crude oil areas of North Alberta, its shallow gas area in South Alberta and its natural gas area in Northwest Alberta. North America capital expenditures also included the expansion of the Company's Primrose properties, where additional wells were drilled in the fourth quarter. Steaming commenced in early 2004 and production from these wells is expected in mid-2004. The construction of the $250 million expansion of the Primrose In-Situ project will commence in the fall of 2004 and is expected to increase production to 90,000 bbl/d of bitumen by 2007 from the current 40,000 bbl/d of bitumen. At Pelican Lake, the enhanced oil recovery waterflood test program was a success and the Company will begin the phased roll out of the waterflood with approximately 20% of the field being under waterflood by the end of 2004. The waterflood will stabilize production but will require a further 63 Pelican Lake productive wells to be converted from producers to water injectors and 87 new wells to be drilled as producers. During the fourth quarter of 2003, two pilot wells were converted to injector status.

Capital expenditures also included work on the Horizon Oil Sands Project ("Horizon Project") where work on the Engineering Design Study ("EDS"), the third and final stage of engineering work, has commenced. In the fourth quarter, the Company completed construction work on the access road and three bridges. The 2004 capital budget for the Horizon Project will be phased in over the year and is dependent on regulatory approval and cost estimates. In 2004, the EDS will be completed with a capital budget of $150 million. Regulatory review for the environmental assessment of the Horizon Project was conducted in September 2003 and the Company received approval from the review panel in January 2004. Final regulatory approvals are expected in the first half of 2004. With final regulatory approval, the completion of the EDS and confirmation of cost estimates, Board of Director approval will be sought in late 2004. Depending upon the timing of final approval, a total of $200 to $400 million is budgeted for the Horizon Project in 2004. The Company anticipates that 80% of the detailed engineering will be completed before it commits to the construction of Horizon Project.

During the fourth quarter, the Company drilled 2 crude oil wells and 1 water injector in the UK sector of the North Sea. In 2004, the Company anticipates drilling approximately 13 crude oil wells, implementing a secondary recovery natural gas injection scheme at Banff, optimizing Ninian and Murchison waterfloods, and continuing its 2003 recompletion program.

During the fourth quarter, development of the Baobab Field continued with the drilling of water injection and production wells. Construction of the Floating Production, Storage and Offtake vessel is currently underway. Production from the Baobab Field is expected to commence in mid 2005. The fourth quarter also included the completion of the drilling of the first of several potential exploration targets located on Block 16, offshore Angola. The well, Zenza-1, in which the Company has a 50% working interest was drilled in 1,300 metres of water, reached a total depth of 3,998 metres and was drilled for a total cost of US $17 million. The well encountered reservoir quality sands in four zones and shows of hydrocarbons were encountered but not of sufficient amounts to be commercial. Accordingly the well has been plugged and abandoned. The results of the well will be integrated into the geological model for Block 16 and a second exploratory well will be drilled in 2005.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)

	Dec 31 2003	Sep 30 2003	Dec 31 2002
Working capital deficit [1]	**$ 505**	$ 528	$ 14
Long-term debt	**2,645**	2,766	4,074
Total	**$ 3,150**	$ 3,294	$ 4,088
Shareholders' equity			
Preferred securities	**$ 103**	$ 108	$ 126
Share capital	**2,353**	2,348	2,304
Retained earnings	**3,644**	3,428	2,414
Foreign currency translation adjustment	**17**	9	24
Total	**$ 6,117**	$ 5,893	$ 4,868
Debt to cash flow[1] [2]	**0.9x**	0.9x	1.8x
Debt to EBITDA[2] [3]	**0.8x**	0.8x	1.6x
Debt to book capitalization[1]	**31.6%**	33.4%	45.6%
Debt to market capitalization[1]	**24.2%**	28.1%	38.9%
After tax return on average common shareholders' equity[2]	**25.7%**	26.4%	13.8%
After tax return on average capital employed[2]	**16.7%**	16.4%	8.9%

(1) Includes current portion of long-term debt.
(2) Based on trailing 12-month activity.
(3) Earnings before interest, taxes, depletion, depreciation and amortization.

The Company recognizes the need for a strong financial position in order to withstand volatile crude oil and natural gas commodity prices and the operational risks inherent in the crude oil and natural gas business environment. In 2003, $740 million of long-term debt was repaid. Long-term debt was also reduced by an additional $529 million as a result of foreign exchange gains. In the fourth quarter, long-term debt was reduced by $14 million through debt repayments and $110 million as a result of foreign exchange gains on the Company's US dollar denominated debt. Higher than budgeted prices received for the Company's products during 2003 have resulted in increased cash flow to the Company in 2003 over the budget established in late 2002. Early in 2003, the Company agreed to allocate a minimum of 50% of its cash flow surplus toward debt repayment. The remaining excess is directed to the Company's authorized share buy-back program and additional expenditures on conventional crude oil and natural gas opportunities. The largest portion of the additional capital expenditures took place in the fourth quarter of 2003 and accordingly did not add materially to Canadian Natural's 2003 average production volumes. As at December 31, 2003, the Company had purchased 2,734,800 common shares for a total cost of $144 million at an average purchase price of $52.51 per common share.

The Company's financial objectives are to maintain a strong balance sheet in order to be in a position to finance its operations, to provide a capital structure that is flexible for future opportunities and unforeseen events, and to maintain strong credit ratings allowing for accessibility to public debt markets. These objectives are extremely important entering into the construction years of the Horizon Oil Sands Project. 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 current strong debt ratings and not issuing additional equity in common shares. The Company is also investigating the use of long-term commodity hedges in order to reduce cash flow risks during the construction phase. The Company could also look to offload capital commitments through the acceptance of complementary business partners, or potentially, project joint venture partners. Recent commodity price increases have significantly strengthened the balance sheet of the Company, placing it in a better position to achieve all three of its guiding principles.

On January 22, 2004, 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 6,690,385 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, 2004 and ending January 23, 2005.

COMMITMENTS

The Company has committed to certain payments over the next five years as follows:

	2004	2005	2006	2007	2008	Thereafter
Natural gas transportation	$ 180	$ 169	$ 143	$ 103	$ 77	$ 194
Oil transportation and pipeline	$ 15	$ 13	$ 13	$ 15	$ 13	$ 167
Offshore equipment operating lease	$ 169	$ 129	$ 75	$ 75	$ 75	$ 367
Electricity	$ 7	$ 2	$ 1	$ -	$ -	$ -
Office lease	$ 20	$ 20	$ 19	$ 17	$ 16	$ 50
Processing	$ 6	$ 5	$ 2	$ -	$ -	$ -
Long-term debt repayments	$ 184	$ 194	$ -	$ 165	$ 40	$ 1,978

SENSITIVITY ANALYSIS [1]

Annualized sensitivities to certain factors, which 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	$88	$0.66	$63	$0.47
Including financial derivatives	$65-88	$0.48-0.66	$46-63	$0.34-0.47
Natural gas – AECO C $0.10/mcf[3]				
Excluding financial derivatives	$35	$0.26	$21	$0.16
Including financial derivatives	$32-34	$0.24-0.25	$19-21	$0.14-0.16
Volume changes				
Crude oil – 10,000 bbl/d	$50	$0.37	$17	$0.12
Natural gas – 10 mmcf/d	$13	$0.10	$5	$0.04
Foreign currency rate change				
$0.01 change in C $ in relation to US $[3]				
Excluding financial derivatives	$48	$0.36	$15	$0.11
Including financial derivatives	$41-44	$0.31-0.33	$10-13	$0.08-0.09
Interest rate change - 1%	$10	$0.08	$10	$0.08

(1) *The sensitivities are calculated based on 2003 fourth quarter results.*
(2) *Attributable to common shareholders.*
(3) *For details of financial derivatives in place, see the interim consolidated financial statement note 9.*

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this document or incorporated herein by reference 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.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: the general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; the foreign currency exchange rates; the economic conditions in the countries and regions in which the Company conducts business; the political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; the industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the ability of the Company to complete its capital programs; the ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the availability and cost of financing; the success of exploration and development activities; the production levels; the uncertainty of reserve estimates; the actions by governmental authorities; the government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); the site restoration costs; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and management's course of action would depend upon its assessment of the future considering all information then available.

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. 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			Year Ended	
	Dec 31 2003	Sep 30 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Daily production (boe/d)	**455,935**	461,882	468,132	**458,814**	420,722
Sales price [1]	**$ 30.64**	$ 31.94	$ 30.54	**$ 33.75**	$ 26.25
Royalties	**4.12**	4.46	4.98	**5.20**	3.91
Production expense [2]	**6.81**	7.17	6.34	**7.15**	5.99
Netback	**19.71**	20.31	19.22	**21.40**	16.35
Midstream contribution[2]	**(0.29)**	(0.24)	(0.24)	**(0.28)**	(0.25)
Administration	**0.58**	0.51	0.41	**0.52**	0.40
Interest	**0.79**	0.83	1.22	**0.94**	1.03
Foreign exchange loss (gain)	**(0.17)**	0.11	0.05	**0.05**	0.02
Taxes other than income tax (current)	**1.02**	0.64	0.35	**0.69**	0.35
Current income tax (North Sea)	**0.07**	0.10	(0.83)	**0.14**	(0.13)
Current income tax (Offshore West Africa)	**0.07**	0.07	0.01	**0.06**	0.04
Current income tax (North America)	**0.07**	0.28	-	**0.26**	-
Current income tax (Large corporations tax)	**0.01**	0.12	0.16	**0.09**	0.14
Cash flow	**$ 17.56**	$ 17.89	$ 18.09	**$ 18.93**	$ 14.75

(1) Including financial instruments and transportation costs.
(2) Excluding intersegment eliminations.

SEGMENTED NETBACK	Year Ended December 31, 2003							
		North America		North Sea		Offshore West Africa		Total
Crude oil and NGLs ($/bbl, except daily production)								
Daily production (bbl/d)		174,895		56,869		10,628		242,392
Sales price[1]	$	27.77	$	42.43	$	36.47	$	31.59
Royalties		3.79		(0.03)		1.08		2.77
Production expense		9.14		14.07		8.68		10.28
Netback	$	14.84	$	28.39	$	26.71	$	18.54
Natural gas ($/mcf, except daily production)								
Daily production (mmcf/d)		1,245		46		8		1,299
Sales price[1]	$	6.14	$	3.03	$	4.37	$	6.02
Royalties		1.38		-		0.13		1.32
Production expense		0.57		1.33		1.39		0.60
Netback	$	4.19	$	1.70	$	2.85	$	4.10
Barrels of oil equivalent ($/boe, except daily production)								
Daily production (boe/d)		382,315		64,469		12,030		458,814
Sales price[1]	$	32.71	$	39.61	$	35.29	$	33.75
Royalties		6.22		(0.03)		1.04		5.20
Production expense		6.05		13.36		8.65		7.15
Netback	$	20.44	$	26.28	$	25.60	$	21.40

(1) Including financial instruments and transportation costs.

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)		**December 31 2003**		December 31 2002
ASSETS				
Current assets				
Cash	**$**	**104**	$	30
Accounts receivable and other		**751**		745
		855		775
Property, plant and equipment (net)		**13,269**		12,500
Deferred charges		**74**		84
	$	**14,198**	$	13,359
LIABILITIES				
Current liabilities				
Accounts payable	**$**	**464**	$	337
Accrued liabilities		**712**		428
Current portion of long-term debt (note 3)		**184**		24
		1,360		789
Long-term debt (note 3)		**2,645**		4,074
Deferred credits (note 4)		**488**		440
Future income tax (note 5)		**3,588**		3,188
		8,081		8,491
SHAREHOLDERS' EQUITY				
Preferred securities		**103**		126
Share capital (note 6)		**2,353**		2,304
Retained earnings		**3,644**		2,414
Foreign currency translation adjustment (note 7)		**17**		24
		6,117		4,868
	$	**14,198**	$	13,359

Commitments (note 10)

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Dec 31 2003	Three Months Ended Dec 31 2002	Year Ended Dec 31 2003	Year Ended Dec 31 2002
Revenue (note 2)	**$ 1,368**	$ 1,397	**$ 5,972**	$ 4,342
Less: royalties	**(173)**	(214)	**(872)**	(600)
	1,195	1,183	**5,100**	3,742
Expenses				
Production	**288**	278	**1,209**	931
Transportation (note 2)	**68**	67	**262**	262
Depletion, depreciation and amortization	**405**	386	**1,565**	1,314
Administration	**24**	17	**87**	61
Stock-based compensation (note 6)	**63**	-	**200**	-
Interest	**33**	53	**157**	159
Foreign exchange (gain) loss	**(87)**	2	**(312)**	(31)
	794	803	**3,168**	2,696
Earnings before taxes	**401**	380	**1,932**	1,046
Taxes other than income tax	**26**	21	**107**	63
Current income tax (note 5)	**9**	(28)	**92**	8
Future income tax (note 5)	**118**	178	**339**	400
Net earnings	**248**	209	**1,394**	575
Dividend on preferred securities, net of tax	**(1)**	(1)	**(5)**	(6)
Revaluation of preferred securities, net of tax	**4**	1	**18**	1
Net earnings attributable to common shareholders	**$ 251**	$ 209	**$ 1,407**	$ 570
Net earnings attributable to common shareholders per common share (note 8)				
Basic	**$ 1.87**	$ 1.56	**$ 10.48**	$ 4.46
Diluted	**$ 1.83**	$ 1.51	**$ 10.14**	$ 4.31

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Year Ended December 31 2003	Year Ended December 31 2002
Balance – beginning of year	**$ 2,414**	$ 1,908
Net earnings	**1,394**	575
Dividend on common shares (note 6)	**(81)**	(64)
Purchase of common shares (note 6)	**(96)**	-
Dividend on preferred securities, net of tax	**(5)**	(6)
Revaluation of preferred securities, net of tax	**18**	1
Balance – end of year	**$ 3,644**	$ 2,414

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended **Dec 31 2003**	Three Months Ended Dec 31 2002	Year Ended **Dec 31 2003**	Year Ended Dec 31 2002
Operating activities				
Net earnings	**$ 248**	$ 209	**$ 1,394**	$ 575
Non-cash items				
Depletion, depreciation and amortization	**405**	386	**1,565**	1,314
Deferred petroleum revenue tax	**(17)**	6	**(9)**	10
Stock-based compensation	**63**	-	**200**	-
Future income tax	**118**	178	**339**	400
Unrealized foreign exchange gain	**(81)**	-	**(320)**	(35)
Cash flow provided from operations	**736**	779	**3,169**	2,264
Deferred charges	**5**	(26)	**10**	(84)
Net change in non-cash working capital	**41**	(100)	**(48)**	(157)
	782	653	**3,131**	2,023
Financing activities				
Repayment of bank credit facilities	**(13)**	(85)	**(647)**	(1,234)
Repayment of senior unsecured notes	**-**	-	**(85)**	(16)
Issue of US dollar debt securities	**-**	-	**-**	1,749
Repayment of obligations under capital leases	**(1)**	(2)	**(8)**	(4)
Issue of common shares	**6**	15	**89**	84
Purchase of common shares	**(21)**	-	**(144)**	-
Dividend on common shares	**(20)**	(17)	**(77)**	(60)
Dividend on preferred securities	**(2)**	(2)	**(9)**	(10)
Net change in non-cash working capital	**(9)**	44	**(11)**	27
	(60)	(47)	**(892)**	536
Investing activities				
Business combination, net of cash acquired	**-**	-	**-**	(843)
Expenditures on property, plant and equipment	**(663)**	(295)	**(2,526)**	(1,752)
Net proceeds on sale of property, plant and equipment	**1**	3	**20**	76
Net expenditures on property, plant and equipment	**(662)**	(292)	**(2,506)**	(2,519)
Net change in non-cash working capital	**14**	(299)	**341**	(25)
	(648)	(591)	**(2,165)**	(2,544)
Increase in cash	**74**	15	**74**	15
Cash – beginning of period	**30**	15	**30**	15
Cash – end of period	**$ 104**	$ 30	**$ 104**	$ 30

Supplemental disclosure of cash flow information (note 11)

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

Stock-based compensation

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.

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. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by employees, officers or directors and the previously recognized liability associated with the stock options is recorded as share capital.

Transportation

In accordance with EIC 123 of the Emerging Issues Committee of the Canadian Institute of Chartered Accountants, transportation costs are no longer netted against revenue but are disclosed as a separate expense in the consolidated statements of earnings.

3. LONG-TERM DEBT

	Dec 31 2003	Dec 31 2002
Bank credit facilities		
Bankers' acceptances	**$ -**	$ 728
US dollar bankers' acceptances (2003 – US $207 million, 2002 – US $150 million)	**268**	237
Medium-term notes	**250**	250
Senior unsecured notes (2003 – US $258 million, 2002 – US $318 million)	**366**	498
US dollar debt securities (2003 – US $1,500 million, 2002 – US $1,500 million)	**1,938**	2,370
Obligations under capital leases	**7**	15
	2,829	4,098
Less: current portion of long-term debt	**184**	24
	$ 2,645	$ 4,074

Bank credit facilities

At December 31, 2003, the Company had unsecured bank credit facilities of $1,925 million comprised of a $100 million operating demand facility and a revolving credit and term loan facility of $1,825 million. The revolving credit and term loan facility is fully revolving for 364-day periods with an initial term to June 2004 and a provision for extension at the mutual agreement of the Company and the lenders. If not extended, the facility converts to a non-revolving loan with a term of two years. The full amount of the outstanding principle would be repayable at the end of year two following the initiation of the term period. The facility provides that the borrowings may be made by way of operating advances, prime loans, bankers' acceptances, US base rate loans or US dollar LIBOR advances which bear interest at the bank's prime rates or at money market rates plus applicable margins. During the year, the Company repaid and cancelled a $500 million acquisition term credit facility.

In addition to the outstanding debt, letters of credit aggregating $69 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.

In September 2003, the Company made the final US $10 million principal repayment on the 6.95% senior unsecured notes due September 30, 2003.

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

	Dec 31 2003	Dec 31 2002
Provision for future site restoration	**$ 447**	$ 440
Stock-based compensation	**41**	-
	$ 488	$ 440

5. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Year Ended	
	Dec 31 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Current income tax expense				
Current income tax – North America	**$ 3**	$ -	**$ 43**	$ -
Large corporations tax – North America	**1**	6	**16**	21
Current income tax – North Sea	**2**	(35)	**23**	(19)
Current income tax – Offshore West Africa	**3**	1	**10**	6
	9	(28)	**92**	8
Future income tax	**118**	178	**339**	400
Income taxes	**$ 127**	$ 150	**$ 431**	$ 408

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

During 2003, the Government of Alberta passed legislation to reduce its corporate income tax rate by 0.5% effective April 1, 2003. Also during 2003, the Canadian federal government passed 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 for actual crown royalties paid is phased in. The Company's future income tax liability was reduced by $31 million with respect to the Alberta corporate income tax rate reduction and by $247 million with respect to the Federal resource income tax rate changes.

6. SHARE CAPITAL

Issued

	Year ended December 31, 2003	
Common shares	**Number of shares (thousands)**	**Amount**
Balance – beginning of year	**133,776**	**$ 2,304**
Issued upon exercise of stock options	**2,690**	**89**
Previously recognized liability on stock options exercised for common shares	**-**	**8**
Purchase of shares under Normal Course Issuer Bid	**(2,735)**	**(48)**
Balance – end of year	**133,731**	**$ 2,353**

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 December 31, 2003, the Company had purchased 2,734,800 common shares for a total cost of $144 million. The excess cost over book value of the shares purchased was applied to reduce retained earnings.

In January 2004, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,690,385 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2004 and ending January 23, 2005. As at February 19, 2004, the Company had not purchased any additional shares using its Normal Course Issuer Bid.

Dividend policy

On February 19, 2004, the Board of Directors set the regular quarterly dividend at $0.20 per common share (2003 - $0.15 per common share). The Company pays regular quarterly dividends in January, April, July, and October of each year.

Stock options

	Year ended December 31, 2003		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of year	**12,882**	**$**	**37.13**
Granted	**668**	**$**	**52.31**
Exercised for common shares	**(2,690)**	**$**	**33.14**
Surrendered for cash settlement	**(1,337)**	**$**	**33.52**
Forfeited	**(629)**	**$**	**42.78**
Outstanding – end of year	**8,894**	**$**	**39.44**
Exercisable – end of year	**2,323**	**$**	**34.65**

Modification of Stock Option Plan

In 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 surrender, multiplied by the number of common shares covered by the stock options surrendered, in lieu of receiving common shares.

The modification to the Option Plan was accounted for prospectively and for the year ended December 31, 2003, the Company recorded compensation expense of $200 million. As at December 31, 2003, the total liability for expected cash settlements under the Option Plan is $171 million, of which $130 million is included as a current liability. As at December 31, 2003, cash payments of $31 million had been made for 1,337,398 stock options surrendered.

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 recognized 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.

	December 31, 2003
Balance – beginning of year	**$ 24**
Unrealized loss on translation of net investment	**(108)**
Hedge of net investment with US dollar denominated debt, net of tax	**101**
Balance – end of year	**$ 17**

8. NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS PER COMMON SHARE

	Three Months Ended		Year Ended	
Weighted average common shares outstanding (thousands)	**Dec 31 2003**	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Basic	**133,937**	133,618	**134,235**	127,883
Effect of dilutive stock options (1)	**-**	2,036	**1,222**	2,744
Assumed settlement of preferred securities with common shares	**1,767**	2,901	**1,954**	2,681
Diluted	**135,704**	138,555	**137,411**	133,308
Net earnings attributable to common shareholders	**$ 251**	$ 209	**$ 1,407**	$ 570
Dividend on preferred securities, net of tax	**1**	1	**5**	6
Revaluation of preferred securities, net of tax	**(4)**	(1)	**(18)**	(1)
Diluted net earnings attributable to common shareholders	**$ 248**	$ 209	**$ 1,394**	$ 575
Net earnings per common share attributable to common shareholders				
Basic	**$ 1.87**	$ 1.56	**$ 10.48**	$ 4.46
Diluted	**$ 1.83**	$ 1.51	**$ 10.14**	$ 4.31

(1) Modification of the Option Plan described in note 6 results in a liability and expense for all outstanding stock options. As such, the potential common shares associated with the stock options are not included in diluted earnings per share effective from the date of modification.

9. 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 February 19, 2004, which includes all transactions outstanding as at December 31, 2003:

	Remaining Term		Volume	Average Price	*Index*
Oil					
Brent differential swaps	Jan 2004 –	Dec 2004	40,000 bbl/d	US $1.22	Dated Brent/WTI
Oil price collars	Jan 2004 –	Mar 2004	123,000 bbl/d	US $25.24 – US $30.87	WTI
	Apr 2004 –	Jun 2004	120,000 bbl/d	US $25.06 – US $29.84	WTI
	Jul 2004 –	Sep 2004	120,000 bbl/d	US $25.63 – US $30.41	WTI
	Oct 2004 –	Dec 2004	60,000 bbl/d	US $25.50 – US $30.32	WTI

	Remaining Term	Volume	Average Price	*Index*
Natural gas				
AECO collars	Jan 2004 – Mar 2004	300,000 GJ/d	C $6.00 – C $10.14	AECO

	Remaining Term		Amount ($ millions)	Average Exchange Rate (US $/C $)
Foreign currency				
Currency collars	Jan 2004 –	Aug 2004	US $20/month	1.51 – 1.59
	Jan 2004 –	Sep 2004	US $5/month	1.52 – 1.59
	Jan 2004 –	Dec 2004	US $3/month	1.45 – 1.54
	Jan 2004 –	Aug 2005	US $10/month	1.37 – 1.49

	Remaining Term	Amount ($ millions)	Exchange Rate (US $/C $)	Interest Rate (US $)	Interest Rate (C $)
Currency swap	Jan 2004 – Dec 2005	US $125	1.55	7.69%	7.30%

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

10. COMMITMENTS

The Company has committed to certain payments over the next five years as follows:

	2004	**2005**	**2006**	**2007**	**2008**	**Thereafter**
Natural gas transportation	$ 180	$ 169	$ 143	$ 103	$ 77	$ 194
Oil transportation and pipeline	$ 15	$ 13	$ 13	$ 15	$ 13	$ 167
Offshore equipment operating lease	$ 169	$ 129	$ 75	$ 75	$ 75	$ 367
Electricity	$ 7	$ 2	$ 1	$ -	$ -	$ -
Office lease	$ 20	$ 20	$ 19	$ 17	$ 16	$ 50
Processing	$ 6	$ 5	$ 2	$ -	$ -	$ -

11. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Three Months Ended		Year Ended	
	Dec 31 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Interest paid	**$ 31**	$ 28	**$ 178**	$ 132
Taxes paid	**$ 24**	$ 67	**$ 51**	$ 160

12. SEGMENTED INFORMATION

	Three Months Ended		Year Ended	
	Dec 31 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Revenue				
North America	**$ 1,076**	$ 1,148	**$ 4,829**	$ 3,610
North Sea	**237**	213	**961**	612
Offshore West Africa	**49**	30	**156**	102
Midstream	**16**	15	**61**	52
Intersegment eliminations	**(10)**	(9)	**(35)**	(34)
	$ 1,368	$ 1,397	**$ 5,972**	$ 4,342
Net Earnings				
North America	**$ 216**	$ 177	**$ 1,206**	$ 565
North Sea	**16**	19	**121**	(1)
Offshore West Africa	**12**	9	**44**	(6)
Midstream	**4**	4	**23**	17
	248	209	**1,394**	575
Dividend on preferred securities, net of tax	**(1)**	(1)	**(5)**	(6)
Revaluation of preferred securities, net of tax	**4**	1	**18**	1
Net Earnings Attributable to Common Shareholders	**$ 251**	$ 209	**$ 1,407**	$ 570
Additions to Property, Plant and Equipment				
North America	**$ 431**	$ 124	**$ 1,769**	$ 1,026
North Sea	**106**	312	**363**	555
Offshore West Africa	**46**	16	**176**	186
Horizon Oil Sands Project	**52**	19	**152**	68
Midstream	**2**	6	**11**	20
Abandonments	**20**	4	**40**	43
Head office	**5**	3	**20**	10
	$ 662	$ 484	**$ 2,531**	$ 1,908

	Property, Plant and Equipment		Total Assets	
	Dec 31 2003	Dec 31 2002	**Dec 31 2003**	Dec 31 2002
Segmented Assets				
North America	**$ 10,841**	$ 10,252	**$ 11,582**	$ 10,917
North Sea	**1,157**	1,277	**1,282**	1,427
Offshore West Africa	**651**	518	**687**	549
Horizon Oil Sands Project	**381**	229	**381**	229
Midstream	**200**	196	**227**	209
Head office	**39**	28	**39**	28
	$ 13,269	$ 12,500	**$ 14,198**	$ 13,359

13. SUBSEQUENT EVENT

On February 18, 2004 the Company acquired certain resource properties located in East Central Alberta and Saskatchewan (collectively known as the Petrovera Partnership) for aggregate consideration of $701 million. In a separate transaction, the Company sold specific resource properties in the Petrovera Partnership, representing approximately one third of the total acquisition, to another independent producer for proceeds of $234 million, resulting in a net cost of $467 million for the retained properties. The net current production from the working interests retained by the Company is approximately 27.5 mbbl/d of heavy oil and 9 mmcf/d of natural gas together with volumes associated with royalty interests of 1.2 mbbl/d of heavy oil and 2 mmcf/d of natural gas.

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated August 2003. 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 December 31, 2003:

Interest coverage (times)	
Net earnings	12.6 [(1)]
Cash flow from operations attributable to common shareholders	21.7 [(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 and the net earnings coverage ratio for the 12-month period ended December 31, 2003 would be 12.0x and the cash flow coverage ratio for the 12-month period ended December 31, 2003 would be 20.5x.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time, on Wednesday, February 25, 2004. The North American conference call number is 1-800-377-5794 and the outside North America conference call number is 1-416-641-6681. Please call in about 10 minutes before the starting time in order to be patched into the call. Should you experience any difficulty in connecting to the call, those in North America please call 1-800-473-0602; and for those outside North America, please call 1-905-502-3723. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural Resources website at www.cnrl.com.

A taped rebroadcast will be available until 11:00 p.m. Mountain Standard Time on Wednesday, March 3, 2004. To access the postview in North America, dial 1-800-558-5253 and enter the passcode 21176715. Those outside North America, dial 1-416-626-4100 and enter the passcode 21176715.

WEBCAST

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

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

2004 FIRST QUARTER RESULTS

2004 first quarter results are scheduled for release on Wednesday, May 5, 2004. A conference call will be held on that day at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time.

ANNUAL GENERAL MEETING

Canadian Natural Resources Limited's Annual and Special Meeting of the Shareholders will be held on Thursday, May 6, 2004 at 3:00 p.m. Mountain Daylight Time in Macleod Hall A, of the Telus Convention Centre, Calgary, Alberta. All shareholders are invited to attend.

For further information, please contact:

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